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Pollution Control Technical Manual for Lurgi-Based Indirect Coal Liquefaction and SNG (Substitute Natural Gas)

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The document is one of six technical handbooks prepared by EPA to help government officials granting permits to build synfuels facilities, synfuels process developers, and other interested parties. They provide technical data on waste streams from synfuels facilities and technologies capable of controlling them. Process technolgies covered in the manuals include coal gasification, coal liquefaction by direct and indirect processing, and the extraction of oil from shale. The manuals offer no regulatory guidance, allowing the industry flexibility in deciding how best to comply with environmental regulations.

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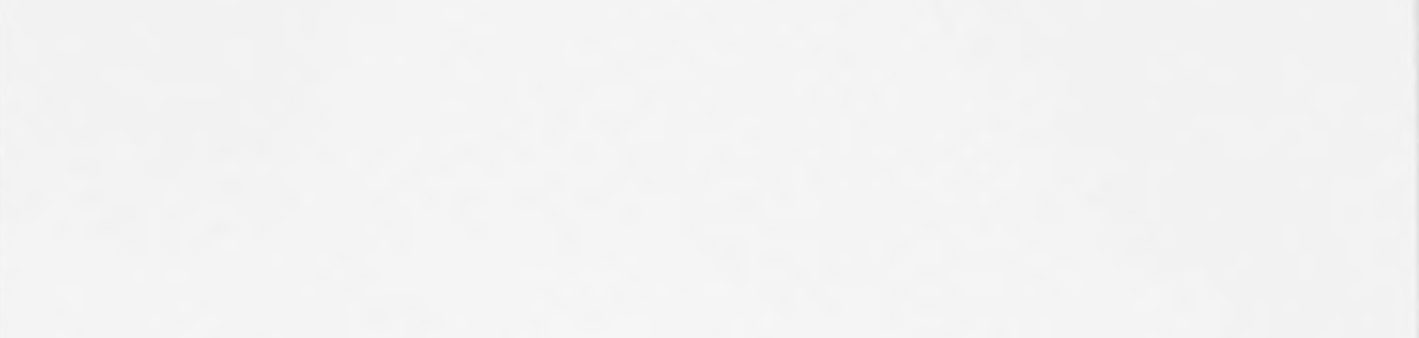

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FOR

Lurgi-Based Indirect Coal Liquefaction and SNG

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DISCLAIMER

This Pollution Control Technical Manual was based on data obtained in EPA's source characterization study at the Kosovo Gasification Plant of the Elektroprivreda Kosovo, Yugoslavia. Data was also provided by the Lurgi Plant at Westfield, Scotland and the SASOL Plant in South Africa. Additional data sources used in this manual included other EPA synfuels characterization studies, environmental impact statements, published literature, and EPA supported engineering calculations. No proprietary or confidential data appear or have been used in the preparation of this manual. Although this manual addresses the Lurgi gasifier based technology, the process developer, Lurgi Kohle and Mineraloltechnik, GmbH, FRG, was not involved in the development of the manual. Thus, the manual does not necessarily represent Lurgi's engineering design data, material balances, or operational information.

This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

FOREWORD

The purpose of the Pollution Control Technical Manuals (PCTMs) is to provide process, discharge, and pollution control data in summarized form for the use of permit writers, developers, and other interested parties. The PCTM series covers a range of alternate fuel sources, including coal gasification and coal liquefaction by direct and indirect processing, and the extraction of oil from shale.

The series consists of a set of technical volumes directed at production facilities based upon specific conversion processes. The entire series is supplemented by a pollution control technology appendix volume which describes the operation and application of approximately 50 control processes.

All PCTMs are prepared on a base plant concept (coal gasification and liquefaction) or developer proposed designs (oil shale) which may not fully reflect plants to be built in the future. The PCTMs present examples of control applications, both as individual process units and as integrated control trains. These examples are taken in part from applicable permit applications and, therefore, are reflective of specific plants. None of the examples are intended to convey an Agency endorsement or recommendation but rather are presented for illustrative purposes. The selection of control technologies for application to specific plants is the exclusive function of the designers and permitters who have the flexibility to utilize the lowest cost and/or most effective approaches. It is hoped that readers will be able to relate their waste streams and controls to those presented in these manuals to enable them to better understand the extent to which various technologies may control specific waste streams and utilize the information in making control technology selections for their specific needs.

The reader should be aware that the PCTMs contain no legally binding requirements or guidance, and that nothing contained in the PCTMs relieves a facility from compliance with existing or future environmental regulations or permit requirements.

Herbert L. Wiser
Acting Deputy Assistant Administrator
Office of Research and Development
U.S. Environmental Protection Agency

ABSTRACT

The Environmental Protection Agency (EPA), Office of Research and Development has undertaken an extensive study to determine synthetic fuel plant waste stream characteristics and to evaluate potentially applicable pollution control systems. The purpose of this and all other PCTMs is to convey this information in a manner that is readily useful to designers, permit writers, and the public.

This specific PCTM addresses coal-based synthetic fuels facilities using dry ash Lurgi gasifiers to generate a synthesis process feed gas. Product synthesis technologies examined in this PCTM include: methanation to produce substitute natural gas (SNG), methanol synthesis, Mobil M-gasoline synthesis from methanol, and Fischer-Tropsch synthesis.

The manual proceeds through a description of the hypothetical base plant, characterizes the waste streams produced in each medium, and discusses the array of commercially available controls which can be applied to the base plant waste streams. From these generally characterized controls, several examples are constructed for each medium in order to illustrate typical control technology applications. Then, example control trains are constructed for each medium, illustrating the function of integrated control systems. Control and control system cost and performance estimates are presented, together with descriptions of the discharge streams, secondary waste streams, and energy requirements. A summary of the gaps and limitations in the data base used to develop this manual is presented along with a listing of additional data needs.

CONTENTS

Page

FOREWORD. iii

ABSTRACT. iv

FIGURES xii

TABLES. xiv

ACRONYMS AND ABBREVIATIONS. xxi

CONVERSION FACTORS. xxiii

ACKNOWLEDGEMENT xxiv

1.0 INTRODUCTION 1

1.1 TECHNOLOGY OVERVIEW. 3

1.2 APPROACH TO MANUAL DEVELOPMENT 4
    1.2.1 Base Plant Definition. 4
    1.2.2 Control Technology Evaluation. 6

1.3 DATA BASE. 7

1.4 MANUAL ORGANIZATION AND UTILIZATION. 10
    1.4.1 Manual Organization. 10
    1.4.2 Manual Utilization 11

2.0 PROCESS OVERVIEW 14

2.1 COAL FEED CHARACTERISTICS AND PRODUCT SLATES 18

CONTENTS (Continued)

Page

2.2 BASE PLANT DESCRIPTION 23
- 2.2.1 Coal Preparation 23
- 2.2.2 Lurgi Coal Gasification. 24
- 2.2.3 Gas Purification and Upgrading 26
- 2.2.4 Product Synthesis. 30
- 2.2.5 Auxiliaries. 33
- 2.2.6 Fugitive Emissions 34

2.3 BASE PLANT CAPITAL INVESTMENT AND ANNUALIZED OPERATING COSTS . . 35

3.0 PROCESS DESCRIPTION AND WASTE STREAM CHARACTERIZATION. 37

3.1 COAL PREPARATION 46

3.2 LURGI GASIFICATION 54
- 3.2.1 Coal Feeding 58
- 3.2.2 Lurgi Gasification 59
- 3.2.3 Ash Removal. 61
- 3.2.4 Waste Stream Characteristics 64

3.3 GAS PURIFICATION AND UPGRADING 73
- 3.3.1 Gas Quenching and Cooling. 73
- 3.3.2 Shift Conversion 77
- 3.3.3 Rectisol Acid Gas Removal. 80
- 3.3.4 Trace Sulfur Removal 86
- 3.3.5 Waste Streams From Gas Purification and Upgrading. . . 87

CONTENTS (Continued)

Page

3.4 PRODUCT SYNTHESIS 100
- 3.4.1 Synthesis of Substitute Natural Gas 100
- 3.4.2 Synthesis of Synthetic Liquid Fuels 102
- 3.4.3 Waste Streams Generated by Synthesis Operations 117

3.5 PRODUCTS AND BYPRODUCTS 124
- 3.5.1 Methanol Synthesis Product 124
- 3.5.2 Fischer-Tropsch Liquid Products 127
- 3.5.3 Mobil M-Gasoline 130
- 3.5.4 Substitute Natural Gas (SNG) 131
- 3.5.5 LPG 132
- 3.5.6 Lurgi Gasification Byproducts 132
- 3.5.7 Ammonia and Sulfur 136
- 3.5.8 Excess Coal Fines 140

3.6 AUXILIARIES 141
- 3.6.1 Raw Water Treatment 141
- 3.6.2 Steam and Power Generation and Process Heating 145
- 3.6.3 Cooling Operations 148
- 3.6.4 Oxygen Production 150
- 3.6.5 Product and Byproduct Storage 151

3.7 FUGITIVE AND MISCELLANEOUS WASTES 157
- 3.7.1 Fugitive Organic Emissions 157
- 3.7.2 Non-Process/Intermittent Wastewater Streams 158
- 3.7.3 Equipment Cleaning Wastes 162

3.8 WASTE STREAM/CONTROL TECHNOLOGY INDEX 164

CONTENTS (Continued)

Page

4.0 EVALUATION OF POLLUTION CONTROL TECHNOLOGY 173

4.1 GASEOUS MEDIUM 181

4.1.1 Rectisol Acid Gases. 186

4.1.1.1 H_2S-Rich Acid Gases 212

4.1.1.2 H_2S-Lean Acid Gases 214

4.1.1.3 CO_2-Rich Acid Gases 220

4.1.2 Small Volume and Intermittent/Transient Waste Gases Containing VOC and Reduced Sulfur Compounds. 221

4.1.2.1 Coal Lockhopper Gases 222

4.1.2.2 Transient (Startup, Shutdown, and Upsets) Waste Gases 227

4.1.2.3 Depressurization and Stripping Gases. . . . 230

4.1.2.4 CO_2-Rich Gases from SNG Production. 231

4.1.3 Transient Process Gases Containing SO_2, CO, and/or Particulates 232

4.1.3.1 Shift Catalyst Regeneration Offgases. . . . 233

4.1.3.2 Mobil M Catalyst Regeneration Offgases. . . 237

4.1.3.3 Carbon Regeneration Flue Gases. 238

4.1.4 Combustion Gases 239

4.1.4.1 Boiler Flue Gases 253

4.1.4.2 Process Heater Flue Gases 259

4.1.4.3 Wastewater Incineration Flue Gases. 260

4.1.5 Fugitive Dust from Material Storage. 263

4.1.6 Particulates from Material Conveying and Processing. . 268

4.1.7 Fugitive VOC Emissions 270

4.1.7.1 Product/Byproduct Storage Emissions 278

4.1.7.2 Fugitive Organic Emissions from Process Equipment 282

CONTENTS (Continued)

Page

4.1.8 Air Pollution Control in Integrated Facilities 286
4.1.8.1 Example 1 - High Sulfur Coal/Selective Rectisol. 286
4.1.8.2 Example 2 - Low Sulfur Coal/Nonselective Rectisol. 296
4.1.8.3 Example 3 - Incineration of Waste Gases in Utility Boilers 302

4.2 AQUEOUS MEDIUM 308
4.2.1 Aqueous Medium Generic Controls. 314
4.2.1.1 Processes for Removal of Suspended Solids, Tars, and Oils. 315
4.2.1.2 Processes for Removal of Bulk Organics. . . 323
4.2.1.3 Processes for Removal of Dissolved Gases. . 330
4.2.1.4 Processes for Removal of Dissolved Organics. 339
4.2.1.5 Processes for Removal of Residual Organics. 353
4.2.1.6 Processes for Removal of Dissolved Inorganics. 364
4.2.1.7 Processes for Volume Reduction. 371
4.2.1.8 Processes for Residual Disposal 379
4.2.2 Control Applications for Specific Streams Containing Primarily Organic Compounds. 384
4.2.2.1 Gas Liquor. 385
4.2.2.2 Rectisol Still Bottoms. 405
4.2.2.3 Synthesis Wastewaters 406
4.2.2.4 Secondary Wastewater Streams. 409
4.2.2.5 Integrated Control Examples for Streams Containing Primarily Organic Compounds. . . 411
4.2.3 Control Applications for Specific Streams Containing Primarily Inorganic Compounds 440

CONTENTS (Continued)

Page

4.3 SOLID WASTE MANAGEMENT 449
  4.3.1 Solid Waste Control. 455
    4.3.1.1 Treatment 458
    4.3.1.2 Reuse/Resource Recovery 460
    4.3.1.3 Disposal. 461
  4.3.2 Inorganic Ashes and Sludges. 469
    4.3.2.1 Gasifier Ash. 469
    4.3.2.2 Boiler Bottom Ash 472
    4.3.2.3 Boiler Fly Ash. 473
    4.3.2.4 Boiler FGD Sludge 474
    4.3.2.5 Dewatered Chemical Precipitation and Raw Water Treatment Sludges 475
  4.3.3 Recovered Byproducts 476
    4.3.3.1 Recovered Elemental Sulfur. 476
    4.3.3.2 Excess Coal Fines 476
    4.3.3.3 Collected Dust from Particulate Control . . . 477
  4.3.4 Organic Sludges. 478
    4.3.4.1 Treatment 478
    4.3.4.2 Disposal. 480
  4.3.5 Spent Catalysts and Sulfur Guard 481
    4.3.5.1 Treatment 482
    4.3.5.2 Resource Recovery and Reuse 482
    4.3.5.3 Disposal. 483

5.0 DATA GAPS AND LIMITATIONS. 484

6.0 REFERENCES 506

CONTENTS (Continued)

Page

APPENDIX A - LURGI DRY ASH COAL GASIFICATION. A-1

APPENDIX B - RECTISOL ACID GAS REMOVAL PROCESS. B-1

APPENDIX C - COSTING METHODOLOGY AND BASE PLANT COSTS C-1

APPENDIX D - THE FATE OF TRACE ELEMENTS IN LURGI GASIFICATION SYSTEMS. D-1

APPENDIX E - MATERIAL BALANCES. E-1

FIGURES

Figure Page

2-1 Simplified block flow diagram of a Lurgi-based synthesis gas production facility. 16

2-2 Simplified block flow diagram for conversion of synthesis gas to SNG or liquid fuels 17

3-1 Process operations and discharge streams associated with Lurgi-based synfuels facilities-main gasification train. . 38

3-2 Fischer-Tropsch synthesis and product upgrading. 39

3-3 Methanol and Mobil M-gasoline synthesis and upgrading. . . 40

3-4 Substitute natural gas production. 41

3-5 Auxiliary processes associated with Lurgi-based synfuels facilities 42

3-6 Simplified block flow diagram of coal preparation. 47

3-7 Lurgi gasifier 55

3-8 Schematic of ash quench system for Lurgi gasification. . . 63

3-9 Raw gas quenching and cooling system 75

3-10 High temperature shift conversion. 79

3-11 Nonselective Rectisol acid gas removal process 83

3-12 Selective Rectisol acid gas removal process. 85

3-13 Methanation and dehydration for SNG synthesis. 101

3-14 ICI methanol synthesis process 106

3-15 Mobil M-Gasoline synthesis and product recovery. 109

3-16 Fischer-Tropsch (Synthol) synthesis and product recovery . 113

3-17 Methanation, CO_2 removal, and drying for co-production of SNG with synthetic liquid fuels 118

3-18 Typical raw water treatment system 142

4-1 Three stage Claus plant with split flow option 196

4-2 Simplified flow diagram of the Stretford process 199

4-3 Schematic flow diagram for example 1-integrated control. . 288

4-4 Schematic flow diagram for example 2 297

4-5 Example 3 - integrated control 303

FIGURES (Continued)

Figure		Page
4-6	Phenosolvan solvent extraction process	326
4-7	The PHOSAM-W process	334
4-8	Wastewater incinerator with quench	359
4-9	Process flow diagram for lime/soda softening system. . . .	367
4-10	Vapor compression evaporation system	376
4-11	Block flow diagram for integrated control example No. 1. .	413
4-12	Block flow diagram for integrated control example No. 2. .	418
4-13	Block flow diagram for integrated control example No. 3. .	422
4-14	Block flow diagram for integrated control example No. 4. .	425
4-15	Block flow diagram for integrated control example No. 5. .	429
4-16	Block flow diagram for integrated control example No. 6. .	432
4-17	Block flow diagram for integrated control example No. 7. .	436
4-18	Landfill designs	463
4-19	Capital investment and annualized unit cost for landfills.	465

TABLES

Table | Page

1-1 Completed and Ongoing Data Acquisition Programs at Coal Gasification Facilities Sponsored or Co-Sponsored by the EPA 8

2-1 Proximate and Ultimate Analyses of Base Plant Coals . . . 19

2-2 Typical Upgraded Product Slates for Lurgi-Based Synthetic Fuels Facilities. 21

2-3 Estimated Base Plant Costs. 36

3-1 Typical Upgraded Product Slates for Lurgi-Based Synthetic Fuels Facilities. 44

3-2 Estimated Overall Material Flows for Coal Preparation Operation 48

3-3 Estimated ROM Coal Storage Pile Capacities. 49

3-4 Estimated Fugitive Particulates from Coal Storage Piles . 51

3-5 Fugitive Particulate Emission Factors for Coal Preparation Operations. 53

3-6 Estimated Material Flows for Lurgi Gasification Operation - Rosebud Coal. 56

3-7 Estimated Major and Minor Components of Raw Lurgi Gas 62

3-8 Estimated Composition of Air-Blown Lurgi Gases. 68

3-9 Polycyclic Organic Matter Identified in Kosovo Byproduct Tars and Oils 68

3-10 Estimated Mass Flows for Gasifier Ash Quenching System. . 71

3-11 Composition and Leaching Characteristics of Unquenched Lurgi Gasifier Ashes. 72

3-12 Estimated Material Flows for Gas Purification and Upgrading - Rosebud Coal. 74

3-13 Available Data for Gas Liquor Depressurization Gases. . . 88

3-14 Estimated Characteristics of Lurgi Gas Liquors. 89

3-15 Concentrations of Organic Compounds Found In Lurgi Gas Liquor (North Dakota Lignite). 91

3-16 Concentration of Polynuclear Aromatic Compounds in Raw and Dephenolized Kosovo Gas Liquors. 92

3-17 Estimated Composition of Spent Shift Catalyst. 94

TABLES (Continued)

Table		Page
3-18	Estimated Compositions of H_2S-Containing Acid Gases from Rectisol (Liquids Synthesis Gases).	95
3-19	Estimated Compositions of CO_2-Rich Offgas from Selective Rectisol	98
3-20	Estimated Composition of Methanol/Water Still Bottoms. .	99
3-21	Estimated Material Flows for SNG Synthesis - Rosebud Coal	103
3-22	Estimated Material Flows for Methanol Synthesis - Rosebud Coal	108
3-23	Estimated Material Flows for Mobil M-Gasoline Synthesis - Rosebud Coal	111
3-24	Estimated Material Flows for Fischer-Tropsch Synthesis - Rosebud Coal	115
3-25	Components Reported in Commercial Methanol	125
3-26	Estimated Composition of Crude Methanol from Coal. . . .	126
3-27	Estimated Composition of Finished Indirect Coal Liquefaction Unleaded Gasolines and Typical Petroleum Gasolines.	128
3-28	Distribution of Oxygenated Byproducts from Fluid-Bed Fischer-Tropsch Synthesis.	129
3-29	Estimated Blending Components for Mobil M-Gasoline . . .	130
3-30	Available Data on the Characteristics of Byproduct Tars.	133
3-31	Polynuclear Aromatic Compounds Found in Byproducts from a Lurgi-Type Gasifier in Kosovo, Yugoslavia	134
3-32	Composition of Benzene Soluble Tars Produced in the Synthane Gasification Process.	135
3-33	Available Data on the Characteristics of Byproduct Oils.	137
3-34	Available Data on Composition of Crude Lurgi Phenols. . .	138
3-35	Composition of Naphtha Oil Produced at the Westfield Lurgi Facility.	138
3-36	Available Characterization Data for Byproduct Naphtha. .	139
3-37	Estimated Primary Demineralizer Regeneration Wastewater .	144
3-38	Estimated Uncontrolled Auxiliary Boiler Flue Gas Compositions.	147

TABLES (Continued)

Table		Page
3-39	Maximum Measured Concentrations of Selected Components in Bottom Ash and Ash Slurry	148
3-40	Water Losses from the Base Plant Cooling Towers	149
3-41	Estimated Characteristics of Cooling Tower Blowdown and Drift	150
3-42	Estimated Product and Byproduct Properties	153
3-43	Estimated Storage Tank Evaporative Emissions	154
3-44	Composition of Evaporative Emissions from Gasoline Storage	155
3-45	Storage Tank Vent Data from Kosovo Plant	156
3-46	Fugitive Emission Factors	159
3-47	Estimated Fugitive Hydrocarbon Emissions	160
3-48	Estimated Average Storm Runoff for Assumed Base Plant Locations	161
3-49	Stream Index	165
3-50	Cross-Reference Index for Primary Waste Streams	169
3-51	Cross-Reference Index for Secondary Waste Streams	171
4-1	Summary of Estimated Gaseous Stream Characteristics in Lurgi-Based Facilities	182
4-2	Categorization of Gaseous Waste Stream in Lurgi Gasification Facilities According to Source Type	184
4-3	Key Features of Hydrocarbon Removal/H_2S Enrichment Processes	189
4-4	Key Features of Bulk Sulfur Removal Processes	194
4-5	Key Features of Residual Sulfur Removal Processes	205
4-6	Key Features of Incineration Processes	210
4-7	Costs for Control of Stretford Oxidizer Vent Gases	219
4-8	Costs Associated with Control of Lockhopper Vent Gases	225
4-9	Costs Associated with Incineration of Transient Waste Gases	229
4-10	Costs for Control of SO_2 in Shift Catalyst Regeneration Offgases	236

TABLES (Continued)

Table		Page
4-11	Cost Estimates for Control of Mobil Catalyst Decommissioning Offgas.	237
4-12	Cost Summary: Carbon Absorption Regeneration Offgas. . .	238
4-13	Combustion Modification Techniques for NO_x Control. . . .	241
4-14	NO_x Flue Gas Treatment Control Alternatives for Boilers .	244
4-15	Key Features of SO_2 Removal Processes	246
4-16	Key Features of Particulate Collection Equipment.	250
4-17	Example Boiler Feed and Potential Emissions Contributions	254
4-18	Control of Particulates in Boiler Flue Gas by ESP (Rosebud Methanol Synthesis Case)	256
4-19	Costs for Wellman-Lord Control of SO_2 in Boiler Flue Gases - Rosebud Coal to Methanol.	258
4-20	Cost Summary of Wastewater Incinerator Flue Gas Controls.	262
4-21	Key Features of Storage Pile Dust Control Technologies. .	264
4-22	Repair Methods for Fugitive Emissions Reduction	275
4-23	Equipment Design/Modifications for Fugitive Hydrocarbon Emissions Control	276
4-24	Storage Tank Emission Estimates	279
4-25	Estimated Incremental Costs for Storage of Synthetic Liquids	281
4-26	Fugitive Organic Emissions from Process Equipment	283
4-27	Capital and Annualized Costs for Fugitive Volatile Organic Compound Emission Controls.	285
4-28	Material Flow for Example 1 Integrated Control - Amine Enrichment of Rectisol and Stripper Overhead Gases. . . .	290
4-29	Material Flow for Example 1 Integrated Control - SCOT Tail Gas Treatment.	291
4-30	Material Flow for Example 1 Integrated Control - BEAVON Tail Gas Treatment.	292
4-31	Material Flow for Example 1 Integrated Control - Wellman-Lord Tail Gas Treatment	293
4-32	Costs Associated with Example 1 Integrated Control. . . .	294

TABLES (Continued)

Table		Page
4-33	Material Flow for Example 2 Integrated Control - Stretford/Incineration	299
4-34	Costs Associated with Example 2 Control	300
4-35	Costs Associated with Example 3 Integrated Control	306
4-36	Summary of Uncontrolled Aqueous Waste Streams Generated in Lurgi-Based Synfuels Facilities	310
4-37	Technologies Potentially Applicable to the Removal of Suspended Solids, Tars, and Oils from Lurgi-Based Synfuels Plant Wastewaters	316
4-38	Technologies Potentially Applicable to the Removal of Bulk Organics from Lurgi-Based Synfuels Plant Wastewaters	324
4-39	Technologies Potentially Applicable to the Removal of Dissolved Gases from Lurgi-Based Synfuels Plant Wastewaters	331
4-40	Technologies Potentially Applicable to the Removal of Dissolved Organics from Lurgi-Based Synfuels Plant Wastewaters	340
4-41	Comparative Performance Data for Activated Sludge Systems Treating Wastewaters from Byproduct Coking and Various Synfuels Processes	343
4-42	Technologies Potentially Applicable to the Removal of Residual Organics from Lurgi-Based Synfuels Plant Wastewaters	354
4-43	Activated Carbon Adsorption Efficiencies for Wastewater Similar to those Expected from Synfuels Facilities	355
4-44	Technologies Potentially Applicable to the Removal of Dissolved Inorganics from Lurgi-Based Synfuels Plant Wastewaters	365
4-45	Technologies Potentially Applicable to Wastewater Volume Reduction of Lurgi-Based Synfuels Plant Wastewaters	372
4-46	Technologies Potentially Applicable to the Disposal of Residuals from the Treatment of Lurgi-Based Synfuels Plant Wastewaters	380

TABLES (Continued)

Table		Page
4-47	Estimated Removal of Bulk Organics from Gas Liquor by Solvent Extraction.	388
4-48	Estimated Removal of Dissolved Gases from Gas Liquor by PHOSAM-W	391
4-49	Estimated Removal of Dissolved Organics from Gas Liquor by Activated Sludge	393
4-50	Estimated Removal of Residual Organics from Gas Liquor by Activated Carbon Adsorption	395
4-51	Estimated Removal of Residual Organics from Gas Liquor by Thermal Oxidation.	397
4-52	Estimated Compositions for use of Treated Gas Liquor as Cooling Tower Makeup.	399
4-53	Estimated Reduction of Gas Liquor Volume by Forced Evaporation	402
4-54	Estimated Composition of Pretreated Gas Liquor for Disposal by Deepwell Injection.	404
4-55	Estimated Composition of Pretreated Gas Liquor for Disposal by Surface Impoundment	404
4-56	Estimated Removal of Dissolved Organics from F-T Synthesis Wastewater by Activated Sludge.	408
4-57	Estimated Removal of Residual Organics from F-T Synthesis Wastewater by Activated Carbon Adsorption	408
4-58	Estimated Material Flows and Compositions - Integrated Control Example No. 1	415
4-59	Estimated Costs - Control Example No. 1	416
4-60	Estimated Material Flows and Compositions - Integrated Control Example No. 2	419
4-61	Estimated Costs - Control Example No. 2	420
4-62	Estimated Material Flows and Compositions - Integrated Control Example No. 3	423
4-63	Estimated Costs - Control Example No. 3	424
4-64	Estimated Material Flows and Compositions - Integrated Control Example No. 4	426
4-65	Estimated Costs - Control Example No. 4	427

TABLES (Continued)

Table		Page
4-66	Estimated Material Flows and Compositions - Integrated Control Example No. 5	430
4-67	Estimated Costs - Control Example No. 5	431
4-68	Estimated Material Flows and Compositions - Integrated Control Example No. 6	434
4-69	Estimated Costs - Control Example No. 6	435
4-70	Estimated Material Flows and Compositions - Integrated Control Example No. 7	438
4-71	Estimated Costs - Control Example No. 7	439
4-72	Summary of Solid Waste Streams From Lurgi-Based Indirect Liquefaction Facilities	450
4-73	Summary of Solid Waste Management Techniques.	456
4-74	Site-Specific Factors to be Considered for Terrestrial Disposal Options.	457
4-75	Estimated Treatment/Disposal Cost for Biosludge	479
4-76	Summary of Flow Rates for Spent Catalysts and Sulfur Guard	481
5-1	Completed and Ongoing Data Acquisition Programs at Coal Gasification Facilities Sponsored or Co-Sponsored by the EPA	485
5-2	Data Gaps and Research Needs - Gaseous Medium	490
5-3	Data Gaps and Research Needs - Aqueous Medium	495
5-4	Data Gaps and Research Needs - Solid Wastes	502
5-5	Data Gaps and Research Needs - Products and Byproducts. .	504

ACRONYMS AND ABBREVIATIONS

ACP	Ammonia from Coal Project
ADA	Anthraquinone disulfonic acid
ADIP	Shell patented diisopropyl amine-based acid gas removal process
AGR	Acid gas removal
BOD	Biochemical oxygen demand
BFW	Boiler feed water
COD	Chemical oxygen demand
CW	Cooling water
DOE	Department of Energy
DOI	Department of Interior
EGD	Effluent Guidelines Division
EP	Extraction Procedure
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERDA	Energy Research and Development Administration
ESP	Electrostatic precipitator
FGD	Flue gas desulfurization
F-T	Fischer-Tropsch
HF	Hydrogen fluoride
HHV	Higher Heating Value
kmol	kg-mole
KO	Knockout
LHV	Lower Heating Value
LPG	Liquified petroleum gas
MAF	Moisture and ash free
NO_x	Nitrogen oxides
NMHC	Non-methane hydrocarbons
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
OPTS	Office of Pesticides and Toxic Substances
OSW	Office of Solid Wastes

ACRONYMS AND ABBREVIATIONS (Continued)

PCTM	Pollution Control Technical Manual
PNA	Polynuclear Aromatics
POM	Polycyclic organic matter
PSD	Prevention of Significant Deterioration
SASOL	South African Coal, Oil and Gas Corporation, Ltd.
SCOT	Shell Claus Off-Gas Treatment
SNG	Substitute Natural Gas
SO_x	Sulfur oxides
TGT	Tail gas treatment
TOC	Total organic carbon
TSP	Total suspended particulates
TSS	Total suspended solids
TVA	Tennessee Valley Authority
VOC	Volatile Organic Compounds
W-L	Wellman-Lord

CONVERSION FACTORS

1.0 kg [kilogram] = 2.205 lb [pound (mass)]

1.0 Mg [megagram (metric ton)] = 1.102 ton [short ton (2000 lb)]

1.0 kg/min [kilogram per minute] = 132.3 lb/hr [pound per hour]

1.0 m^3 [cubic meter] = 264.2 gal [gallon]

1.0 Nm^3/hr [normal cubic meter (at 273 K) per hour] = 37.32 scfh [standard cubic feet (at 60°F) per hour]

1.0 GJ [gigajoule] = 0.9479×10^6 Btu [British thermal unit]

1.0 MW [megawatt] = 3.413×10^6 Btu/hr [British thermal unit per hour]

1.0 MJ/s [megajoule per second] = 3.413×10^6 Btu/hr [British thermal unit per hour]

1.0 kWh [kilowatt hour] = 3413 Btu [British thermal unit]

1.0 MJ/Nm^3 [megajoule per normal cubic meter (at 273 K)] = 25.40 Btu/scf [Btu per standard cubic foot (at 60°F)]

1.0 g/Nm^3 [gram per normal cubic meter (at 273 K)] = 0.413 gr/scf [grains per standard cubic foot (at 60°C)]

1.0 kPa [kilopascal] = 0.00987 atmosphere

1.0 kg mole = 22.4 Nm^3 (32°F)

Prefixes

T = tera = 10^{12} G = giga = 10^9 M = mega = 10^6 k = kilo = 10^3

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SECTION 1
INTRODUCTION

Future U.S. energy production envisions the development of an environmentally acceptable synthetic fuels industry. As part of this overall effort, the Environmental Protection Agency (EPA), Office of Research and Development, has for the past several years undertaken extensive studies to determine synthetic fuel plant waste stream characteristics and potentially applicable pollution control systems.

The purpose of the Pollution Control Technical Manuals (PCTMs) is to convey, in a summarized and readily useful manner, information on synfuel waste stream characteristics and pollution control technology as obtained from studies by EPA and others. The documents provide waste stream characterization data and describe a wide variety of pollution controls in terms of estimated performance, cost, and reliability. The PCTMs contain no legally binding requirements, no regulatory guidance, and include no preference for process technologies or controls. Nothing within these documents binds a facility to accepting the example emission control process(es) in the service(s) indicated nor relieves a facility from compliance with existing or future environmental regulations or permits.

The Pollution Control Technical Manuals consist of several discrete documents. There are six process-specific PCTMs and a more general appendix volume which describes over fifty pollution control technologies. Application of pollution controls to a particular synfuel process is described in each process specific manual. These volumes are:

Pollution Control Technical Manual for Lurgi-Based Indirect
Coal Liquefaction and SNG

Pollution Control Technical Manual for Koppers-Totzek-Based Indirect
Coal Liquefaction

Pollution Control Technical Manual for Exxon Donor-Solvent Direct Coal Liquefaction

Pollution Control Technical Manual for Lurgi Oil Shale Retorting with Open Pit Mining

Pollution Control Technical Manual for Modified In Situ Oil Shale Retorting Combined with Lurgi Surface Retorting

Pollution Control Technical Manual for TOSCO II Oil Shale Retorting with Underground Mining

Control Technology Appendices For Pollution Control Technical Manuals

By focusing on specific process technologies, the PCTMs attempt to be as definitive as possible on waste stream characteristics and control technology applications. This focus does not imply any EPA recommendations for particular process or control designs. Those described in the manuals are intended as representative examples of processes and control technologies that might be used. The organization of the PCTMs from process description through waste stream characterization and control technology evaluation provides the user with a number of alternative approaches to understanding the environmental consequences in operating synthetic fuel plants.

Control technology configurations presented in the PCTMs reflect pollutant removal levels which are believed to be achievable with currently available control technologies based upon existing data. Since there are no domestic commercial scale synfuels facilities, the data base supporting this document is from bench- and pilot-scale synfuel facilities, developer's estimates, engineering analyses, analogue domestic industries, and non-U.S. commercial synfuel plants. As commercial synthetic fuel plants are built, the EPA will continue conducting research in order to develop a more comprehensive data base. In the interim, the Agency encourages facility planners, permit officials, and other interested parties to take advantage of, and interact with EPA to improve, the information contained in these documents.

1.1 TECHNOLOGY OVERVIEW

This specific PCTM addresses coal-based synthetic fuels facilities using dry ash Lurgi gasifiers to generate a raw synthesis process feed gas. The basic sequence of process steps necessary to produce synthetic gaseous and/or liquid fuels from coal using dry ash Lurgi gasifiers is as follows.

Coal is prepared to gasifier feed specifications and gasified. The raw synthesis gas from the gasifier is quenched and upgraded for synthesis by dust removal, shift conversion, and acid gas removal. The purified synthesis gas is then converted into crude gaseous/liquid products which can either be used directly as fuels or further refined. Product synthesis technologies examined in this document include: methanation to produce substitute natural gas (SNG), methanol synthesis, Mobil M-gasoline synthesis from methanol, and Fischer-Tropsch (F-T) synthesis. Significant auxiliary processes required to support a facility of this type are those required for steam and power generation, oxygen production, raw water treatment, and process cooling.

The dry ash Lurgi process is a commercially viable process which has been widely used outside the U.S. to produce industrial fuel gas and synthesis gas from coal. However, of those foreign facilities, only those operated by the South African Coal, Oil, and Gas Corp., Ltd. (SASOL) are representative of the completely integrated facilities (i.e., coal gasification and product synthesis) addressed in this document. The SASOL facilities produce a wide range of crude and refined liquid products utilizing Fischer-Tropsch technology as the primary product synthesis step.

To date, the Lurgi gasifier has been used primarily to gasify low rank coals. The technology has demonstrated the capability to handle highly caking coals such as those used during the trials of American coals at Westfield, Scotland (1) and at SASOL, where a Kentucky No. 9 coal was gasified (2). Companion technologies have also been developed for gas cooling/heat recovery, gas liquor treatment, acid gas removal, and byproduct (tar, oil, naphtha, phenol, and ammonia) recovery. The methanol and F-T synthesis processes have been commercially applied for the production of liquids from coal-derived synthesis gases. The methanation and Mobil processes, although yet to be commercially demonstrated on coal-derived synthesis gases, have been operated on a pilot scale and are considered ready for commercial application.

1.2 APPROACH TO MANUAL DEVELOPMENT

1.2.1 Base Plant Definition

In order to define the process operations and waste streams associated with representative Lurgi-based synthetic fuels facilities, a series of uncontrolled base plants were defined. These base plants incorporate many of the features seen in the Lurgi-based plants which are either proposed, under construction, or in operation. In this context, an uncontrolled base plant is one which has full production capability (all of the equipment required to produce saleable products) but no equipment to control pollutant discharges. Auxiliary processes included in the base plant were those that could render a facility essentially self-sufficient in energy; i.e., one requiring only run-of-mine coal, raw water, and various chemicals and catalysts as inputs. Three different coals (Montana Rosebud subbituminous, Illinois No. 6 bituminous, and Dunn County, North Dakota lignite) were examined as feeds to these facilities. These feeds represent different ranks of coals with various heating values and moisture, sulfur, and ash contents. Using these coals, the expected range of uncontrolled (i.e., base plant) waste streams for which treatment and/or disposal could be considered, were estimated.

A base plant size corresponding to the production of approximately 120 TJ/day of clean synthesis gas was selected as representative of the sizes of the modules of the first plants that may be built. The energy output rate (after synthesis) of a plant of this size is approximately equivalent to the energy content of 20,000 bbls/day of gasoline. Using various data sources (discussed below), material flows and energy usages were estimated for all base plant feedstock/synthesis process combinations.

Uncontrolled waste stream characteristics were estimated using overall material balance calculations and available compositional data from bench-, pilot-, and commercial-scale facilities based on similar technologies. The reader should recognize that Lurgi-based facilities built in the U.S. may contain design features that will result in different uncontrolled waste stream characteristics. Therefore, users of this manual should carefully consider the design features of a particular facility before making judgements concerning uncontrolled waste stream composition and the applicability and performance of candidate control technologies for these streams.

The use of the base plant concept in this manual is not intended to imply that facilities would be designed for U.S. sites without controls. In fact, proposed designs have generally addressed these uncontrolled waste streams (which are pollution control inlet streams) with control techniques. In addition, control equipment is not generally designed as an "end of pipe" technique. Process and control equipment would usually be designed in an integrated fashion for a specific site in order to obtain cost-effective, environmentally-responsive facilities. The non-site-specific base plant concept is used in this manual to facilitate the presentation of data for waste stream characteristics and candidate control techniques, and to make the information more generally applicable.

1.2.2 Control Technology Evaluation

Pollution control technology information is presented in three ways in each process-specific PCTM. First, available pollution controls are identified and information on their operating principles, performance capabilities, reliability, and costs are presented. The information presented is intended to provide insight concerning factors that impact the application of each control technique to the types of waste streams generated by the subject synfuel technology. The second presentation of pollution control information focuses on the application of example controls to specific waste streams. This information is intended to provide insight concerning factors associated with a specific waste stream that impact the application of each control technique to that waste stream. The third type of pollution control information is a presentation of integrated control systems for individual streams, or combinations of streams. The integrated control systems are intended to be illustrative examples of the overall performance and costs of pollution controls for selected waste streams.

Since very limited data on the performance of pollution controls are available from actual operating synthetic fuels plants, many assumptions were made to extrapolate the experience gained with controls in related industries. These assumptions have been carefully documented in the appropriate sections of this manual. Waste streams resulting from pollution control processes (secondary waste streams) and controls for those streams were also identified. Cost estimates for all controls were developed based upon published data and vendor-supplied estimates. These data were extrapolated to the first quarter of 1980 to provide a consistent basis for comparing the relative costs of alternate controls. Base (uncontrolled) plant costs were extrapolated in a similar manner. This allowed the impacts of pollution control costs upon total facility costs to be estimated.

Users of this PCTM should recognize that there are two very significant limitations associated with the use of the data presented.

- First, no fully integrated, well controlled commercial plants of the type discussed in this manual have been constructed to date. Thus, in using the data base presented here, users are cautioned to take careful note of the documented limitations in the data and assumptions made to resolve apparent differences in data obtained from test facilities having widely differing feedstocks, designs, operating characteristics, and site specific constraints.

- Second, this manual does not attempt to address all of the issues that will arise in the selection and design of environmental control systems for new synthetic fuels facilities. Streams that are covered by existing source-based regulations or that are similar to waste streams routinely encountered in other industries for which regulatory precedents already exist, are recognized but not treated in depth.

It should be noted that this PCTM focuses primarily on controls for point and fugitive sources of pollution and not on the ambient impacts of those waste streams. In addition, this manual does not address issues related to coal mining and transportation, worker health and safety, noise, socioeconomic, or ecological impacts.

1.3 DATA BASE

Since the early 1970s, the EPA has sponsored a significant environmental assessment program addressing technologies for producing synthetic fuels from coal. This work has involved a combination of theoretical studies and plant data acquisition programs. These efforts have contributed to both the data and background knowledge used in the development of this manual. Table 1-1

TABLE 1-1. COMPLETED AND ONGOING DATA ACQUISITION PROGRAMS AT COAL GASIFICATION FACILITIES SPONSORED OR CO-SPONSORED BY THE EPA

Facility	Information Classification	Coal Used	Products
Medium/High Btu Gasification and Indirect Liquefaction Facilities (Foreign)			
• Lurgi or Lurgi-Type Gasification			
- Kosovo, Yugoslavia	Data acquisition	Lignite	Medium Btu gas
- SASOL, S.A.	Plant visit and discussions	Low rank bituminous	Various via indirect liquefaction
- Westfield, Scotland	Plant visit and discussions	Various	Test center
• Koppers-Totzek Gasification			
- Modderfontein, S.A.	Data acquisition	High vol. "B" bituminous	Ammonia
- Ptolemais, Greece	Data acquisition (TVA & EPA)	Bituminous	Ammonia
- Kutahya, Turkey	Plant visit and discussions	Lignite	Ammonia
• Winkler Gasification			
- Kutahya, Turkey	Plant visit and discussions	Lignite	Ammonia
• Texaco Gasification			
- Federal Republic of Germany	Data acquisition (EPRI, TVA, & EPA)	Ill. No. 6 bituminous	Test center
Low-Btu Gasification Facilities (U.S.)			
• Wellman Galusha			
- Site No. 1	Data acquisition	Anthracite	Fuel gas
- Site No. 2	Data acquisition	Lignite	Test center
• Chapman/Wilputte	Data acquisition	Low sulfur bituminous	Fuel gas
• Riley	Data acquisition	Lignite	Test center
• Stoic (Foster Wheeler)	Data acquisition (DOE & EPA)	Western bituminous	Fuel gas
Control Research Facilities			
• Raw/Acid Gas Cleanup (Fluidized Bed Gasifier)	North Carolina State University	Various	Test center
• Wastewater Treatability Studies	University of North Carolina	Various	Test center
• Pollutant Identification (Bench Scale Gasifier)	Research Triangle Institute	Various	Test center
• Ash Leaching Evaluations	University of Illinois	Various	Test center
Other Domestic Facilities			
• Texaco Gasification			
- Ammonia from coal plant, TVA	Data acquisition	Bituminous	Ammonia
• Rectisol Acid Gas Cleanup	Texaco, Wilmington, California	Oil partial oxidation	Process hydrogen

lists the major contributing data acquisition programs sponsored or cosponsored by the EPA. As indicated, the data encompass specific research projects, pilot-level sampling and analysis projects, and source sampling of foreign and domestic commercial production facilities.

Data sources employed for the development of base plant/process configurations were primarily engineering studies sponsored by DOE and EPA. The major sources of data used to define the types and characteristics of uncontrolled synthetic fuels facility waste streams were 1) an EPA-sponsored test program of a Lurgi-type gasification facility in the Kosovo region of Yugoslavia (3), 2) an Energy Research and Development Administration (now the Department of Energy [DOE])-sponsored program involving the gasification of American coals in a Lurgi gasifier at Westfield, Scotland (1), 3) SASOL plant test data provided to EPA by SASOL (4), 4) a DOE-sponsored gasoline-from-coal research study conducted by the Mobil Research and Development Corporation (5), and 5) various permit filings and environmental impact statements for proposed U.S. Lurgi-based SNG facilities (6,7,8).

Data sources that served as the basis for the analysis of pollution control applicability and costs include the above engineering studies, studies conducted by the Tennessee Valley Authority (TVA), various permit filings, and technical information obtained from pollution control equipment vendors, process developers, and published literature sources. In addition, data were derived from applications of candidate controls in related industries such as the petroleum refining, natural gas processing, byproduct coking, electric utility, and coal preparation industries. Section 4 of this manual and the PCTM-Pollution Control Technology Appendices identify the sources of data used.

1.4 MANUAL ORGANIZATION AND UTILIZATION

1.4.1 Manual Organization

This Pollution Control Technical Manual is presented in six sections and five Appendices. Following this introductory section are:

Section 2	An overview of the operations and auxiliary processes (base plants) addressed in this manual.
Section 3	A description of the sources and characteristics of the waste streams generated by the operations and auxiliary processes.
Section 4	An analysis of the performance capabilities and costs of potentially applicable pollution control processes including controls for those waste streams generated by the control processes themselves.
Section 5	A summary of the quality of the data base used for waste stream characterizations and control technology analysis.
Section 6	A listing of references for Sections 1 through 5.

Details relating to the assumptions and bases used to calculate the estimated base plant material flows and costs are presented in Appendices A through E of this volume. Detailed discussions of pollution control processes presented in Section 4 can be found in the Control Technology Appendices for Pollution Control Technical Manuals, a separate volume.

Section 2 will be most useful to readers seeking general, summary-type knowledge of the characteristics of the process technologies which this manual addresses. Detailed information about the characteristics of the technologies and specific uncontrolled waste streams is presented in Section 3. This section also describes how the characteristics of those streams are likely to be impacted by differences in coal feed characteristics, process design features, and plant operating characteristics. In light of the intended use of this manual, Section 4 is probably the most important; it presents estimates of the performance capabilities and costs of controls which have been or could be proposed for use in the subject facilities. Users of information presented in Sections 3 and 4 should take careful note of the data limitations and additional data needs summaries presented in Section 5. These summaries are presented to give users of this manual insight concerning the quality of the data used to estimate both uncontrolled base plant waste stream characteristics and control equipment performance capabilities and costs.

1.4.2 Manual Utilization

This manual can be used to satisfy a variety of needs. Some users will be interested in the entire contents of the manual, while others will be interested only in obtaining information on one specific waste stream or pollution control process. To aid those users interested in only a part of the information contained in this PCTM or those whose most pressing needs are for information on a specific waste stream or control technique, a brief description of how to find certain types of information within this manual is provided below.

Descriptions of the Lurgi-based synfuels facilities (base plants) addressed in this PCTM are presented in Section 3, where they are subdivided according to the various operations and auxiliary processes found in the facilities, i.e., coal preparation, Lurgi gasification, gas purification and upgrading, etc. The uncontrolled waste streams generated by each of these operations are identified, quantified, and characterized along with the description of the operations. Thus, a user interested in a particular operation: Lurgi gasification, for example, should turn to Section 3.2 - Lurgi Gasification - to find a summary of the available information on the Lurgi gasification process and the waste streams it produces.

Pollution control equipment performance and cost information is presented in Section 4, organized according to the characteristics of the waste stream being treated. For example, Section 4.1 (Gaseous Medium) presents information on those air pollution control processes which are candidates for use in first generation Lurgi-based synthetic fuels plants. Within Section 4.1 subsections provide brief control technology descriptions and present general performance, secondary waste stream, and costs for air pollution controls applicable to the treatment of several categories of gaseous waste streams.

Following the general descriptions of control technologies for each waste stream category in Section 4.1 are specific discussions of the performance, secondary waste streams, and costs associated with the applications of example candidate control techniques to specific gaseous waste streams in that category. For example, Section 4.1.1.1 discusses the capabilities and costs of specific control processes applied to H_2S-rich Acid Gases. Following all of the waste stream category discussions are illustrative examples of potential integrated control schemes (i.e., multiple control techniques used in series) for those streams or combinations of streams which would normally use more than a single control (due to multiple pollutant loadings or other reasons). Similar types of information are presented for water pollution controls and solid waste management techniques in Sections 4.2 and 4.3, respectively. Additional "how to use" information is presented at the beginning of Section 4 as well as at the beginning of Subsections 4.1, 4.2, and 4.3.

To aid users in finding information on both the characteristics of an uncontrolled waste stream and the available pollution controls for that stream, a cross reference index is provided at the end of Section 3 (Table 3-50). This table lists 1) all of the uncontrolled base plant waste streams and indicates the subsection in Section 3 that contains detailed characterization data for each stream and 2) the subsections in Section 4 that contain information on potentially applicable pollution controls for each stream. Thus, a user interested in a particular waste stream could refer to Table 3-50 and find out which parts of Sections 3 and 4 address that waste stream. Table 3-51, also at the end of Section 3, provides similar information on the pollution controls discussed in Section 4, the secondary waste stream(s) generated by those controls, and available controls for the secondary waste stream(s).

Section 5 provides a discussion of the data gaps and limitations associated with the data base used in the preparation of this manual. These gaps include both waste stream characterization and pollution control performance and cost data. Users of the manual are encouraged to refer to this section for insight into the quality of the information evaluated in Sections 3 and 4.

SECTION 2

PROCESS OVERVIEW

This section presents a brief description of the operations and non-pollution control auxiliary processes expected to be included in Lurgi-based indirect liquefaction and substitute natural gas (SNG) facilities. It also identifies the major waste streams associated with those operations and processes. In this context, waste stream refers to the uncontrolled wastes generated, i.e., before the application of any pollution control device. It should be noted that many of these waste streams are routinely routed to pollution control systems in Lurgi-based plants. As such, the waste streams identified should not necessarily be construed as discharge streams.

The operations and processes described in this section comprise what is called an "uncontrolled base plant" or "base plant" in that they are all required to produce marketable products and byproducts. According to this definition, the "base plant" excludes those processes whose primary function is to treat waste streams to render them suitable for discharge or reuse within the plant. The use of the base plant concept in this manual is not intended to imply that facilities would be designed for U.S. sites without controls. In fact, proposed designs have generally addressed the uncontrolled waste streams (which are pollution control inlet streams) with control techniques. In addition, control equipment is not generally designed as an "end of pipe" technique. Process and control equipment would usually be designed in an integrated fashion for a specific site in order to obtain cost-effective, environmentally-responsive facilities. The non-site-specific base plant concept is used in this manual to facilitate the presentation of data for waste stream characteristics and candidate control techniques, and to make the information more generally applicable.

Section 2
Process Overview

Base plant operations discussed here include coal preparation, coal gasification, gas purification and upgrading, crude product synthesis and separation, and product upgrading. Auxiliary processes discussed include steam and power generation, process cooling, product storage, raw water treatment, and oxygen production. Base plant capital investment and operating costs are also summarized.

Figure 2-1 presents a simplified block diagram of a synthesis gas production facility utilizing oxygen-blown dry ash Lurgi gasifiers. The processes associated with the synthesis and purification of SNG, Fischer-Tropsch liquids, methanol, and gasoline-range hydrocarbons via the Mobil M process are shown in Figure 2-2. These base plant flow schemes are based upon published conceptual designs (5,6,8) and are believed to be representative of the first generation of Lurgi-based indirect liquefaction and SNG facilities that will be built in the U.S.

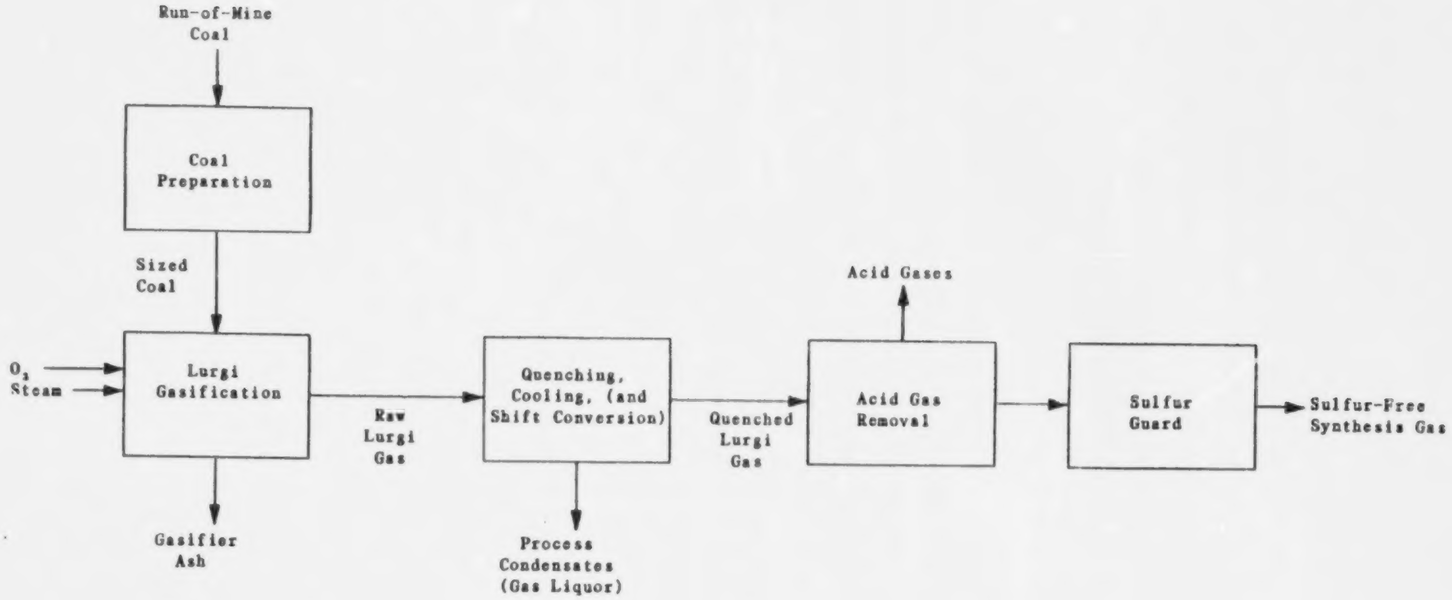
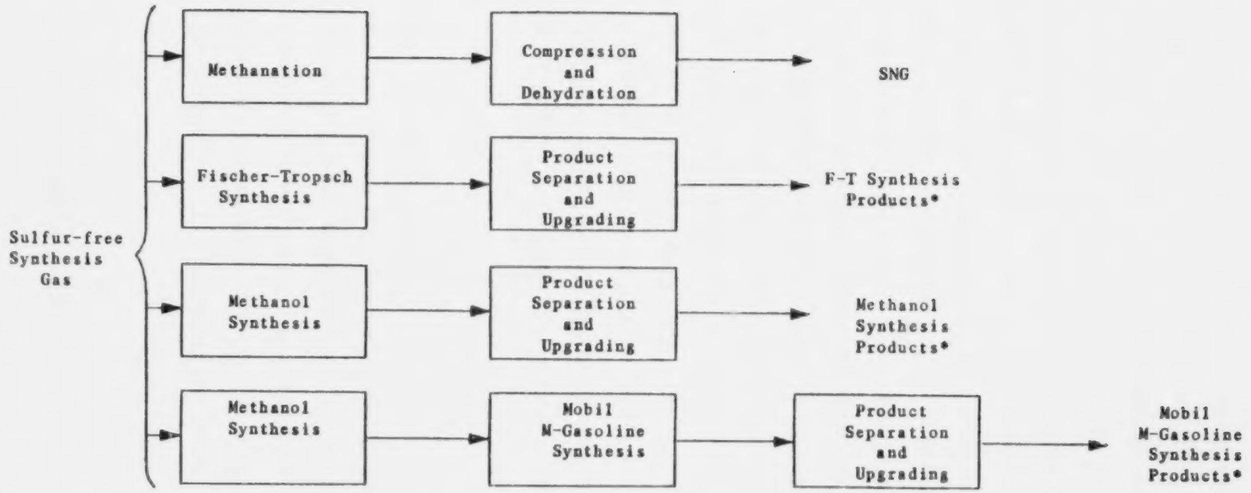


Figure 2-1. Simplified block flow diagram of a Lurgi-based synthesis gas production facility


Sulfur-free Synthesis Gas
Methanation
Compression and Dehydration
SNG
Fischer-Tropsch Synthesis
Product Separation and Upgrading
F-T Synthesis Products*
Methanol Synthesis
Product Separation and Upgrading
Methanol Synthesis Products*
Methanol Synthesis
Mobil M-Gasoline Synthesis
Product Separation and Upgrading
Mobil M-Gasoline Synthesis Products*

*includes SNG coproduct

Figure 2-2. Simplified block flow diagram for conversion of synthesis gas to SNG or liquid fuels

2.1 COAL FEED CHARACTERISTICS AND PRODUCT SLATES

A wide variety of domestic coals are potential feedstocks for Lurgi-based synthetic fuels facilities. Each coal will have associated with its use a specific set of process and waste stream characteristics. Three types of coals were chosen for examination in this PCTM to illustrate the effects that different coal types will have on waste stream generation rates, compositions, and ultimately waste stream treatment options and costs. These coals include a western subbituminous coal (Montana Rosebud), a Midwestern bituminous coal (Illinois No. 6), and a lignite (Dunn County, North Dakota). These coals were chosen to allow calculations of base plant material flows and uncontrolled waste stream flow rates. The coals chosen represent the major classes of coals in the U.S. They also reflect a range of coal rank and moisture, ash, and sulfur contents, which are the major coal characteristics influencing waste stream characteristics. Further, all three coals have been gasified in Lurgi gasifiers. Hence, some data are available which can be used in calculating base plant material flows and identifying waste stream characteristics. All base plants were assumed to be mine-mouth, i.e., they are located near the coal sources in Montana, Illinois, and North Dakota. Table 2-1 presents data on the characteristics of these coals.

In developing the base plant material balances, a nominal plant capacity of 120 TJ (the energy equivalent of about 20,000 barrels of gasoline) per day of synthesis gas was used. Due to differences in the feed coal characteristics, varying amounts of coal (in terms of both mass and energy content) are required as feed to the Lurgi gasifiers to produce this quantity of synthesis gas. The estimated base plant gasifier coal requirements are summarized as follows:

Estimated Coal Requirements	Subbituminous (Montana Rosebud)	Bituminous (Illinois No. 6)	Lignite (Dunn County, ND)
Mg per day	7110	5800	9,590
TJ per day	142	155	143

TABLE 2-1. PROXIMATE AND ULTIMATE ANALYSES OF BASE PLANT COALS

Composition	Subbituminous (Montana Rosebud)[a]	Bituminous (Illinois No.6)[a]	Lignite (Dunn County, ND)[b]
Proximate Analysis, wt %			
Moisture	24.7	10.2	38.6
Volatile Matter	29.2	34.7	27.0
Fixed Carbon	36.4	46.0	27.6
Ash	9.7	9.1	6.8
Higher Heating Value, MJ/kg	20.0	26.6	15.0
Ultimate Analysis, wt % (dry basis)			
Carbon	67.2	71.5	63.6
Hydrogen	4.2	4.8	4.4
Nitrogen	1.2	1.4	0.6
Sulfur	1.5	3.1	1.3
Chloride	<0.1	0.1	0.1
Ash	12.9	10.1	11.1
Oxygen (by difference)	13.0	9.0	18.9

[a] From data contained in Reference 1.

[b] From data contained in Reference 9.

In addition to the gasifier coal requirements, most Lurgi-based synfuels facilities are expected to include onsite coal-fired auxiliary boilers. The size, and hence fuel requirements, of these boilers will depend on a variety of factors, including:

- whether the facility's power requirements are satisfied by purchasing power or by onsite generation,
- the design of the facility's waste energy recovery system,
- the characteristics of the coal being gasified, i.e., the gasifier steam and oxygen requirements,
- whether Lurgi liquid byproducts and high energy content waste gases are used as boiler fuel, and
- the planned disposition of excess coal fines.

Due to the large number of variables that can affect the auxiliary boiler coal requirements, it is difficult to estimate the quantity of boiler coal required for each type of synfuels plant examined in this PCTM. In general, auxiliary boiler energy requirements are expected to range from about 15 to 30 percent of the coal energy input to the gasifier (5,8,10).

Table 2-2 lists typical upgraded product slates for the Lurgi-based synfuels plants examined in this PCTM. It should be noted that large quantities of methane are present in Lurgi synthesis gas. For reasons which are discussed in Section 2.2.4, it is assumed that this methane would be recovered as a coproduct SNG in those facilities producing synthetic liquid fuels rather than reformed to produce additional synthesis gas.

As indicated in Table 2-2, the total energy content of the products from each type of plant varies, even though the same quantity of synthesis gas (nominally 120 TJ per day) is assumed in all cases. This is a reflection of the different energy conversion efficiencies and product slates associated with the four different synthesis operations examined.

TABLE 2-2. TYPICAL UPGRADED PRODUCT SLATES FOR LURGI-BASED SYNTHETIC FUELS FACILITIES

Product	SNG Synthesis	Methanol Synthesis	Mobil M-Gasoline	Fischer-Tropsch
SNG	100	54	55	65
C_3 LPG	-	-	2	2
C_4 LPG	-	-	3	<1
Methanol	-	49	-	-
Gasoline	-	-	37	22
Diesel Oil	-	-	-	4
Heavy Fuel Oil	-	-	-	1
Mixed Alcohols	-	-	-	3
TOTAL PRODUCTS	100	103	97	97

Note: All units are TJ/day. Product slates shown are based on gasifying 142 TJ/day of Rosebud subbituminous coal to produce a synthesis gas feed of approximately 120 TJ/day. In addition to the indicated products, the following quantities of byproducts are produced regardless of synthesis process: Naphtha - 2.0 TJ/day; Tars - 5.5 TJ/day; Oils - 5.9 TJ/day; and Phenols - 1.1 TJ/day. Similar quantities of products and byproducts result from use of the other coals examined in this PCTM (See Appendix E).

It should be noted that the information presented in Table 2-2 is not necessarily reflective of the relative overall energy conversion efficiencies for the four types of plants. The information shown is for gasification of a given quantity of coal (142 TJ/day for the Rosebud subbituminous coal cases shown) and hence indicates the coal-gasified-to-products efficiency. Overall energy conversion efficiencies include the coal energy required to fuel the auxiliary boiler. Since these quantities will vary among synthesis plants (even for a given coal feed), the relative overall plant efficiencies may be different from the relative coal-gasified-to-products efficiencies.

2.2 BASE PLANT DESCRIPTION

2.2.1 Coal Preparation

The coal preparation operation in a Lurgi-based synfuels facility will be similar to those found in other coal-based plants such as coal-fired power plants. Equipment is provided to receive, transport, and store coal and to prepare a sized coal feed for the Lurgi gasifiers and a pulverized coal feed for onsite coal-fired steam boilers.

Run-of-mine (ROM) coal received by conveyor, unit train, barge, or truck is diverted to either an active or inactive (emergency) storage pile as necessary. Coal from storage is transported by a belt conveyor to the preparation plant where it is screened and crushed to a 3.8 cm top size. A 3.8 cm x 0.64 cm coal fraction is separated and conveyed to the gasifier feed storage silos. (Depending on the properties of the coal, a sized coal within the range of 0.3 cm to 7.5 cm can be gasified; the 3.8 cm x 0.64 cm range shown is merely a representative example.) The undersize coal is stored in separate fine coal storage silos. As required to meet the auxiliary steam boiler fuel requirements, coal is removed from the fine coal storage silos and pulverized to nominally 70 percent through 200 mesh. Excess undersized coal may or may not be produced depending on the feed coal characteristics. If excess undersized coal is produced, it could be used to generate export power, gasified in a reactor capable of handling coal fines to produce additional synthesis gas, sold as a byproduct, or disposed of as a solid waste. A potential, but currently undemonstrated, alternative is to pelletize the undersized coal to a nominal 3.8 cm size for use as Lurgi gasifier feed.

The major waste streams associated with the coal preparation operation are ROM storage pile runoff, fugitive dust emissions from prepared coal storage and conveying, and dust from coal crushing and screening. Runoff from ROM coal storage tends to contain high levels of suspended and dissolved solids and can be quite acidic in the case of Midwestern or Eastern coals. Dust from coal preparation consists of natural soil and overburden material as well as coal.

2.2.2 Lurgi Coal Gasification

The dry ash Lurgi gasifier is a medium pressure (2.1 to 3.2 MPa), moving bed gasifier operating below the coal ash fusion temperature. Essentially all types of coals with moisture contents below about 40 percent can be gasified, although strongly caking coals require the use of a coal distributor equipped with a stirrer. In recent tests, gasifying a medium caking coal (free swelling index of 4.5) in a modified (coal distributor with stirrer) Mark IV Lurgi gasifier resulted in 10 to 25 percent reduction in throughput rates (2). The gasifier unit consists of a coal lockhopper, a water-jacketed pressurized gasifier vessel, an ash lockhopper, and an ash quench system.

Sized coal is stored in a coal hopper directly above the gasifier and is fed to the gasifier via a coal lockhopper. Cooled or raw Lurgi gas or an inert gas such as CO_2 or N_2 can be used as the lockhopper pressurant gas. As the coal descends through the gasifier countercurrent to gas flow, it passes through "zones" of progressively higher temperatures which provide for drying, devolatilization, gasification, and combustion. A revolving grate at the bottom of the gasifier supports the ash/coal bed, provides for a uniform flow of ash to the ash lockhopper, and distributes steam and high purity oxygen uniformly across the bottom of the downward moving coal bed. The ash lockhopper allows for discharge of the ash into the ash quench system. Quenched ash is transported as a wet solid or water slurry to a clarification and solids handling system.

The hot crude gas leaving the gasifier is composed primarily of hydrogen, carbon monoxide, carbon dioxide, methane, and unreacted steam. Also present are high molecular weight organics (e.g., tars, oils, phenols), reduced sulfur and nitrogen compounds (e.g., H_2S, COS, mercaptans, NH_3, HCN), low molecular weight hydrocarbons (e.g., C_2s-C_5s, benzene, toluene), and entrained coal dust. Waste streams generated by the gasification operation include coal lockhopper vent gases, ash lockhopper vent gases, gasifier ash, ash quench blowdown, and transient waste gases (e.g., startup gases).

The composition of the coal lockhopper vent gases reflects the characteristics of both the raw Lurgi gas and the lock pressurant gas. When Lurgi gases are used for lock pressurization, the lock vent gases are similar in composition to the Lurgi gases and contain organics and volatile sulfur- and nitrogen-containing compounds. Coal lockhopper vent gases may also contain entrained particulates consisting of coal particles and tarry hydrocarbon materials. When CO_2 or N_2 is used for lock pressurization, a flow of pressurizing gas into and through the lockhopper is maintained in order to minimize, or possibly eliminate, the backflow of raw gas. As a result, the lockhopper gases will consist almost entirely of the pressurization gas, e.g., N_2 or CO_2. Transient gases generated during gasifier startup, shutdown, and upset conditions contain the same types of substances as coal lockhopper gases do when Lurgi gases are used as the lockhopper pressurant.

Ash from the Lurgi gasifier is similar to ash from coal combustion in that it consists almost entirely of mineral matter originally present in the coal. However, gasifier ash will have somewhat higher levels of residual carbon. Ash lockhopper vent gases consist primarily of steam with some entrained particulate matter (ash fines). Ash quench blowdown is similar to bottom ash quench blowdown from coal combustion in that it contains high levels of suspended solids (mainly ash particles) and dissolved solids. The pH of the blowdown depends mainly on the chemical (i.e., leaching) characteristics of the gasifier ash.

2.2.3 Gas Purification and Upgrading

The gas purification and upgrading operation consists of 1) gas cooling and quenching to reduce the gas temperature for subsequent processing and to remove condensible organics, moisture, entrained particulates, and water-soluble inorganics; 2) shift conversion, if necessary, to obtain the required ratio of H_2 to CO for product synthesis; 3) acid gas treatment for removal of CO_2 and reduced sulfur compounds; and 4) removal of trace sulfur compounds using "sulfur guards".

During purification and upgrading of raw Lurgi gases, most of the impurities removed from the gas become components of waste streams. Thus, the gas purification and upgrading operation generates some of the most important waste streams in an integrated Lurgi-based synfuels facility from the standpoint of volume and pollutant concentrations.

Gas Cooling and Dust/Heavy Organics Removal

Raw Lurgi gas is cooled in stages with some heat recovery via steam generation. Initial cooling is carried out in a "wash cooler". Gas from the wash cooler is further cooled in a waste heat boiler which produces medium pressure steam. Moisture and heavy organics such as tars, oils, and phenols are condensed as the raw gas is cooled, producing a gas liquor stream which is routed to the gas liquor separation unit. The gas liquor also contains soluble gaseous species such as ammonia, sulfides, cyanides, and carbon dioxide. In the gas liquor separation unit, dissolved gases, tars, and oils are separated from the water in a depressurization vessel followed by phase separators. The gas washing process also removes essentially all of the dust entrained in the raw gas, which subsequently becomes admixed with the tar. The separated oils and tars are recovered as byproducts which can be used as onsite fuels, sold as byproducts, gasified in an auxiliary partial oxidation gasifier to produce additional synthesis gas, or upgraded into materials suitable for blending with other facility products. Dusty tar from the tar separator can be recycled (to extinction) to the top of the gasifier (2) or gasified in an auxiliary partial oxidation gasifier to produce additional synthesis gas. Gas liquor and depressurization gases are the major waste streams leaving the gas liquor separation unit.

Lurgi gas liquor contains appreciable quantities of dissolved/suspended organic compounds. Inorganics present are mainly ammonia and bicarbonate, with smaller amounts of sulfide, sulfite, sulfate, thiocyanate, and cyanide. This liquor also contains trace elements which were scrubbed from the raw gas or leached from the entrained coal particles that were scrubbed from the gas. In general though, Lurgi gas liquor contains low levels of inorganic suspended and dissolved solids. The quantity of gas liquor generated is determined by the moisture content of the raw gas, which in turn is a function of the coal moisture content and the gasifier feed steam-to-coal ratio. In general, as the quantity of gas liquor generated (per unit of coal gasified) increases, the pollutant concentrations in the gas liquor decrease.

Shift Conversion

Gases suitable for feed to methanol or hydrocarbon (i.e., Fisher-Tropsch or Mobil M-gasoline) synthesis processes should have slightly greater than a 2:1 ratio of hydrogen-to-carbon monoxide and no more than a few percent carbon dioxide. Depending on the specific coal gasified and/or the degree of CO_2 removal obtained in the downstream acid gas removal step, "shifting" of a portion of the Lurgi gas may be required to obtain the necessary ratio. On the other hand, methanation to produce SNG requires an H_2-to-CO_x ratio of at least 3:1 (3:1 for CO and 4:1 for CO_2). Since this ratio is not normally present in Lurgi gas, a shift conversion step is necessary.

The water-gas shift reaction of carbon monoxide and water vapor to form hydrogen and carbon dioxide is an exothermic reaction which can be promoted by a variety of catalysts. For application to Lurgi-based synfuels facilities, it is desirable to conduct the shift reaction at moderate to high temperatures (greater than 500 K) for reasons of thermal efficiency. "Sulfided" cobalt molydate-based catalysts, which are active at temperatures above 500 K, are not affected by the presence of gaseous sulfur compounds. Cobalt molydate-based catalysts are also active for the hydrolysis of carbonyl sulfide. HCN may also be partially hydrogenated to NH_3 over the catalyst.

Shift catalysts must be periodically regenerated to remove accumulated carbon deposits. This is accomplished by controlled oxidation with air to burn off carbon and reduced sulfur. An offgas is produced containing large amounts of oxidized sulfur. After a few regeneration cycles, shift catalysts lose activity due to physical degradation or accumulation of chemical poisons and must be replaced. Thus, spent shift catalyst and catalyst regeneration/-decommissioning offgases are the major waste streams from shift conversion.

Acid Gas Removal

The removal of H_2S and other sulfur compounds from quenched Lurgi gas is necessary to prevent catalyst poisoning in subsequent SNG, methanol, Mobil M-gasoline, and Fischer-Tropsch synthesis operations. The removal of most of the CO_2 is necessary to obtain a gas composition meeting the stoichiometric requirements for synthesis feed gas.

All existing Lurgi systems use the Rectisol process for acid gas removal (AGR). This process is based upon the physical absorption of CO_2, H_2S, COS, and high molecular weight organic compounds in cold methanol. A Rectisol unit can be operated in either a nonselective or a selective mode. With non-selective operation, CO_2 and sulfur species are removed together and a single acid gas stream is produced when the methanol is regenerated. With selective operation, both an H_2S-rich and a CO_2-rich acid gas stream are produced. Both modes of operation remove high molecular weight hydrocarbons from the gas stream. The resulting naphtha stream can be used as an onsite fuel, sold as a byproduct, or upgraded for blending with other facility products.

Waste streams generated by the Rectisol process include acid gases and methanol/water still bottoms. In the case of nonselective Rectisol, the acid gas stream is expected to contain up to 4 percent H_2S and 500 to 1500 ppmv COS plus mercaptans (for the coals considered). In the case of selective Rectisol, the H_2S-rich stream is expected to contain 10 percent or more H_2S and most of the COS plus mercaptans removed from the quenched Lurgi gas, while the CO_2-rich acid gas stream should contain less than 100 ppmv total sulfur compounds (mostly COS). Recent designs of selective Rectisol units in non-Lurgi applications have indicated levels of 10 ppmv or less of total sulfur compounds in the CO_2-rich stream.

Water condensed from the quenched Lurgi gases entering the Rectisol unit and water added to enhance recovery of the byproduct naphtha leave the Rectisol unit as methanol/water still bottoms. This stream will contain small amounts of cyanides, sulfides, ammonia, chlorides, methanol, and other organics.

Trace Sulfur Removal

To protect synthesis catalysts from sulfur poisoning, zinc oxide guard beds may be used following the Rectisol process to remove residual traces of sulfur compounds. Ordinarily, the Rectisol process can attain levels down to 0.1 ppmv total sulfur species in the synthesis feed gas, but ZnO beds would provide insurance against sulfur species being present in the synthesis feed gas during periods of Rectisol process upsets. Periodically, sulfur guard material must be decommissioned and replaced. Thus, if sulfur guards are used, a solid waste consisting of spent ZnO/ZnS is generated.

2.2.4 Product Synthesis

Synthesis of SNG

Methanation of synthesis gases involves the catalytic reaction of the hydrogen and carbon oxides in the gases to produce methane.

$$3H_2 + CO \rightarrow CH_4 + H_2O + \text{heat}$$
$$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O + \text{heat}$$

The resulting product gases have, after dehydration, a composition and higher heating value comparable to that of natural gas.

The methanation reactions, which are carried out over nickel-based catalysts, are highly exothermic. Reaction temperatures are controlled by recycle of product gas. Normally a methanation unit consists of two reactors in series with the bulk of the reaction taking place in the first reactor. Additional equipment includes heat exchangers, a knockout drum to condense and remove moisture, and a product recycle gas system. If the SNG is to be transported via pipelines over long distances, a compression and dehydration unit (such as a triethylene glycol system) would also be required.

Waste streams from a methanation unit include condensate from the methanation unit, offgases from the dehydration unit, spent catalysts, and catalyst decommissioning offgases. Condensate recovered from the production of SNG should be sufficiently pure to be reused within the facility, e.g., as boiler feedwater. However, some dissolved gases will be present and may need to be removed. Spent catalysts will likely be returnable to a vendor for reclamation of their metal content. Catalyst decommissioning offgases may contain CO, particulate matter, and possibly $Ni(CO)_4$.

Synthesis of Liquid Fuels

Methanol synthesis and hydrocarbon production via Fischer-Tropsch (F-T) synthesis can be represented by the following reactions:

$$CO + 2H_2 \rightarrow CH_3OH + heat \qquad \text{(Methanol Synthesis)}$$

$$nCO + (2n + 0.5x)\, H_2 \rightarrow C_nH_{2n+x} + nH_2O + heat \qquad \text{(F-T Synthesis)}$$

where n ranges from 1 to about 20 and is determined by process operating conditions, $x = 2$ for paraffins and $x = 0$ for olefins. Synthesis gas usually contains some CO_2 and inerts (e.g., N_2, CH_4) in addition to CO and H_2. Because synthesis catalysts are also active for the hydrogenation of CO_2, the presence of CO_2 does not create problems (although it does require larger quantities of H_2) as long as the synthesis gas contains the proper ratio of $H_2/(CO + CO_2)$. Methanol synthesis employs Cu/Zn-based catalysts at 470 K and 3.5 to 7.0 MPa while F-T synthesis proceeds at pressures up to 2.5 MPa over iron-based catalysts at 590 to 600 K (fluidized bed reactors) or 490 to 530 K (fixed bed reactors) (5).

Mobil M-gasoline synthesis from methanol can be represented as follows:

$$nCH_3OH \rightarrow C_nH_{2n+x} + (2n - 0.5x)\, H_2O \qquad \text{(Mobil M-Gasoline Synthesis)}$$

This process employs zeolite-based catalysts and operates at about 570 to 680 K and 2.1 MPa (5).

The crude liquid fuel products of methanol, F-T, and Mobil M-Gasoline synthesis processes will require upgrading (probably on site) to yield final products which are marketable as substitutes for petroleum-derived products. This is particularly true for motor gasolines, where crude Fischer-Tropsch gasoline fractions would not meet octane requirements for the retail market in the U.S. F-T and Mobil M-Gasoline products could be upgraded by HF alkylation of the C_3-C_4 fraction to yield gasoline-blend hydrocarbons and commerical grade LPG, by hydrotreating (in the F-T case) for destruction of olefins and oxygenated organics, by catalytic reforming to produce more cyclic and branched chain hydrocarbons, by C_5/C_6 isomerization to increase the anti-knock quality of pentanes and hexanes, and by catalytic polymerization to convert propene/butene fractions into higher molecular weight gasoline blending compounds. All of these upgrading processes are expected to use currently available petroleum refinery technology. Waste streams generated during these upgrading operations are not expected to present any unique treatment problems. For these reasons and due to the multiplicity of possible options for product upgrading, waste stream characteristics and pollution control alternatives for product upgrading processes are not specifically discussed in this PCTM.

All of the synthetic liquid fuels synthesis processes generate a purge gas containing large amounts of methane and unreacted CO_x and H_2. Several options are available to handle the purge gas including use as an onsite fuel, reforming to generate additional synthesis gas, or conversion of the residual hydrogen and carbon oxides into additional methane to produce SNG. Because Lurgi-derived synthesis gases initially contain large amounts of methane and because SNG has considerable market value, the methanation option was selected for analysis purposes in this PCTM. In actual practice, the decision regarding the disposition of synthesis purge gases involves site- and design-specific considerations which are outside the scope of this document.

The methanation reactions are the same as those discussed earlier in this section on Synthesis of SNG. Following methanation, residual CO_2 and moisture are removed, and the byproduct SNG is compressed to pipeline pressure for distribution.

2.2.5 Auxiliaries

The major auxiliaries required to support Lurgi-based synfuels facilities are: 1) steam/power boilers, 2) makeup water treatment, 3) process cooling water, 4) liquid product/byproduct storage, and 5) oxygen production.

The most significant source of waste streams from the auxiliary processes is the steam/power boiler. The boiler flue gases are particularly important because the boilers will generally be coal-fired and because of the potential for using the boilers to combust a wide range of gaseous, liquid, and solid wastes. Energy-rich streams which are candidates for use as boiler fuels include coal fines; byproduct tars, oils, phenols, and naphtha; and hydrocarbon-rich acid gases. In addition to flue gases, waste streams resulting from boiler operations include boiler blowdown condensates, bottom ashes, and spent equipment cleaning wastes.

The major waste streams from makeup water treatment are sedimentation pond sludges, lime/soda softener sludges, and demineralizer regeneration wastewaters from the boiler feedwater treatment unit. Evaporation, drift, and cooling tower blowdown are the major waste streams from the cooling water system.

Storage of synthesis products and Lurgi byproducts is accompanied by evaporative emissions. These vapors consist primarily of low molecular weight organic compounds and, in the case of gasolines and Lurgi byproducts, aromatic compounds such as benzene and toluene.

The oxygen plant itself is not a major source of waste streams. However, as a major consumer of energy, it impacts the magnitude of the waste streams produced in other units, particularly in the steam/power generation unit and the cooling water system.

2.2.6 Fugitive Emissions

There are many potential sources of fugitive emissions in a Lurgi-based synfuels facility. Examples of these sources are pump and compressor seals, inline process valves, pressure relief devices, open-ended valves, sampling connections, flanges, and cooling towers. The characteristics of these potential emissions are highly dependent on the composition of the fluid being handled. In general though, volatile organics, reduced sulfur species, and carbon monoxide are the pollutants expected to be most commonly present. The quantity of fugitive emissions arising from any source is a function of several factors. Three of the more important factors are 1) the type of device (e.g. fugitive emission rates from flanges are different than those from sampling connections), 2) the composition of the fluid being handled (e.g. an inline process valve on a pure hydrocarbon stream would have a higher potential leak rate for volatile organics than a valve on a stream containing only minor quantities of hydrocarbons), and 3) applied maintenance.

2.3 BASE PLANT CAPITAL INVESTMENT AND ANNUALIZED OPERATING COSTS

In order to provide a basis for evaluating the economic impacts that pollution controls could have on synfuels plant costs, estimates of base plant capital costs and total annualized operating costs were developed. These estimates were developed from published economic and engineering studies of the subject technologies (5,11). Capital costs for pollution controls were subtracted, to the extent that they could be quantified, from the published estimates. The resulting uncontrolled capital cost estimates were then adjusted to a base plant capacity of approximately 120 TJ per day of synthesis gas. Finally, the adjusted base plant costs were escalated to first quarter 1980 dollars using the CE plant cost index.

Capital costs presented in this manual are total depreciable investment costs. Included in the total depreciable investment costs are 1) installed equipment costs (including the costs of purchasing and delivering equipment and the directly related costs of installation such as wiring, piping, labor, etc.), 2) indirect installation charges (including construction and engineering costs, contractor fees, and contingency), and 3) interest during construction. Startup costs are not included in the capital costs presented, but could be a significant additional cost for new technologies such as those examined in this PCTM. Total annualized costs presented include 1) labor and maintenance, 2) raw materials, utilities, chemicals, and catalysts, 3) overhead charges, and 4) capital-related charges (including interest on working capital, taxes, insurance, and capital recovery). Capital recovery was calculated as 13.7 percent of the total depreciable base plant investment cost.

Details of the methodology, assumptions, and bases used to develop the base plant capital investment and total annualized operating cost estimates are presented in Appendix C. A summary of the estimates is presented in Table 2-3.

TABLE 2-3. ESTIMATED BASE PLANT COSTS[a]

Type of Synfuel Facility	Total Depreciable Investment $\$10^6$	Total Annualized Operating Cost, $\$10^6$/yr		
		Subbituminous coal (Montana Rosebud)	Bituminous coal (Illinois No. 6)	Lignite (Dunn County, ND)
SNG	810	200	235	215
Methanol	820	200	240	215
Mobil M	910	220	255	235
Fischer-Tropsch	980	235	270	250

[a] A base plant is one which has all of the equipment necessary to produce saleable products, but no pollution control equipment. Each base plant produces approximately 120 TJ/day of synthesis gas; this is equivalent to approximately 20,000 barrels/day of gasoline. All costs are in first quarter 1980 dollars. Details on how these estimates were developed are presented in Appendix C.

SECTION 3
PROCESS DESCRIPTION AND WASTE STREAM CHARACTERIZATION

This section presents detailed descriptions of the operations and auxiliary processes expected to be found in Lurgi-based synthetic fuels facilities. Along with the process description information is a presentation of characterization data (both test and calculated data) for the major process and waste streams associated with those operations and auxiliaries. Figure 3-1 is a block flow diagram showing the coal preparation, Lurgi gasification, and gas purification and upgrading operations. Figures 3-2 through 3-4 are block flow diagrams for the crude product synthesis and product upgrading operations. Auxiliary processes are shown in Figure 3-5, and include raw water treatment, steam and power generation, oxygen production, process cooling water, and product/byproduct storage.

The process sequences indicated in Figures 3-1 through 3-5 were developed from information presented in conceptual and proposed designs of Lurgi-based synfuels facilities (5,6,8). They are believed to be reasonably representative of the configurations or configuration options which are likely to be incorporated into the first Lurgi-based synfuels facilities built in the U.S.

The remainder of this section presents information on the above operations and auxiliaries and on the characteristics of the waste streams they generate. In this context, waste stream refers to the uncontrolled wastes generated, i.e., before the application of any pollution control device. It should be noted that many of these waste streams are routinely routed to pollution control systems in Lurgi-based plants. As such, the waste streams identified should not necessarily be construed as discharge streams.

In addition, some streams identified as waste streams in this manual are expected to be recycled, reused, and/or further processed for recovery of valuable constituents. An example of this type of stream is the high pressure

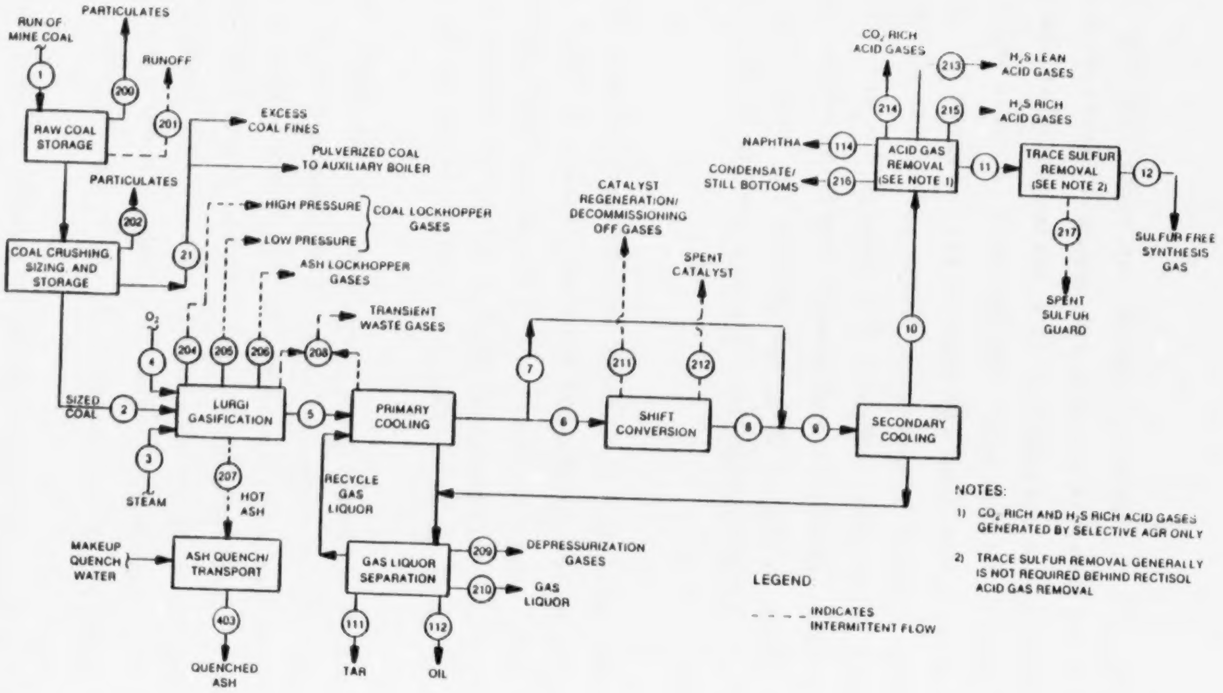


Figure 3-1. Process operations and discharge streams associated with Lurgi-based synfuels facilities--main gasification train

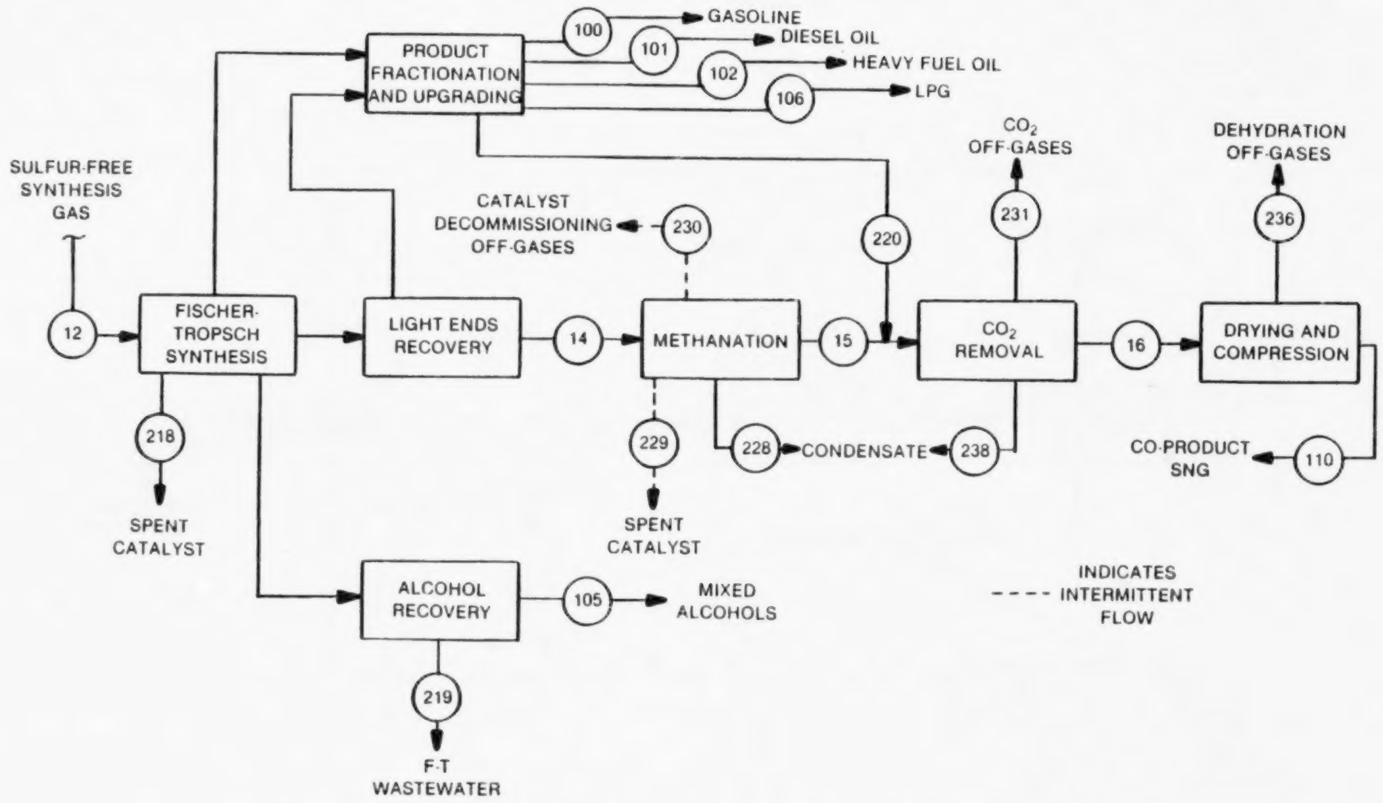


Figure 3-2. Fischer-Tropsch synthesis and product upgrading

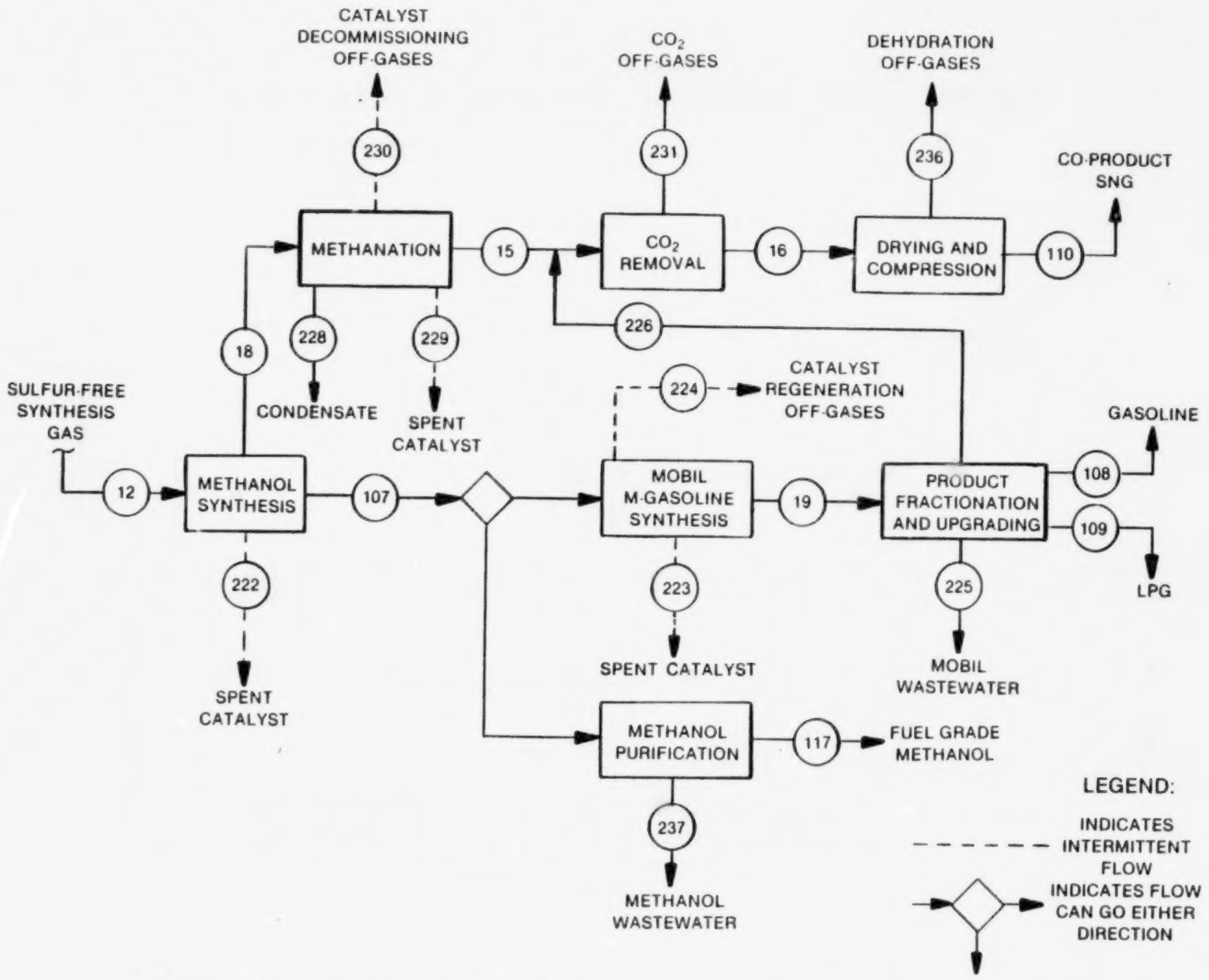


Figure 3-3. Methanol and Mobil M-gasoline synthesis and upgrading

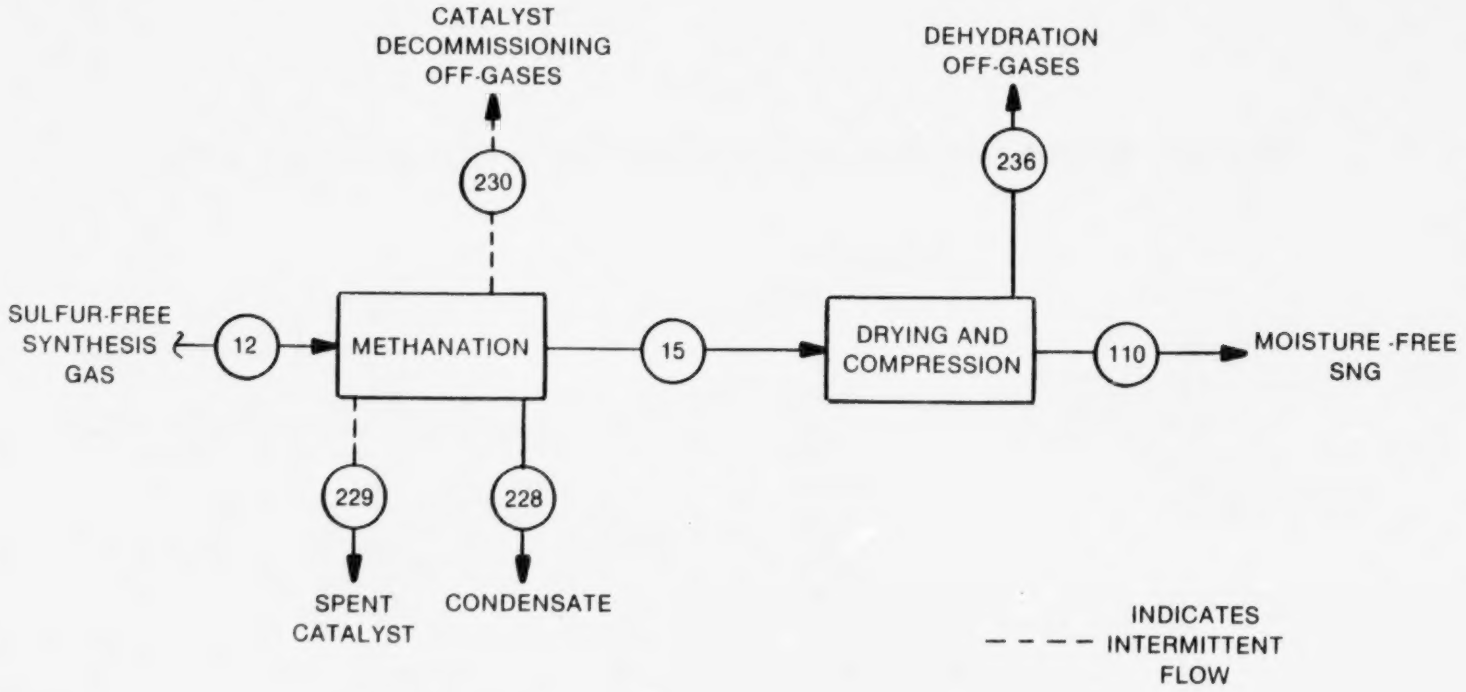


Figure 3-4. Substitute natural gas production

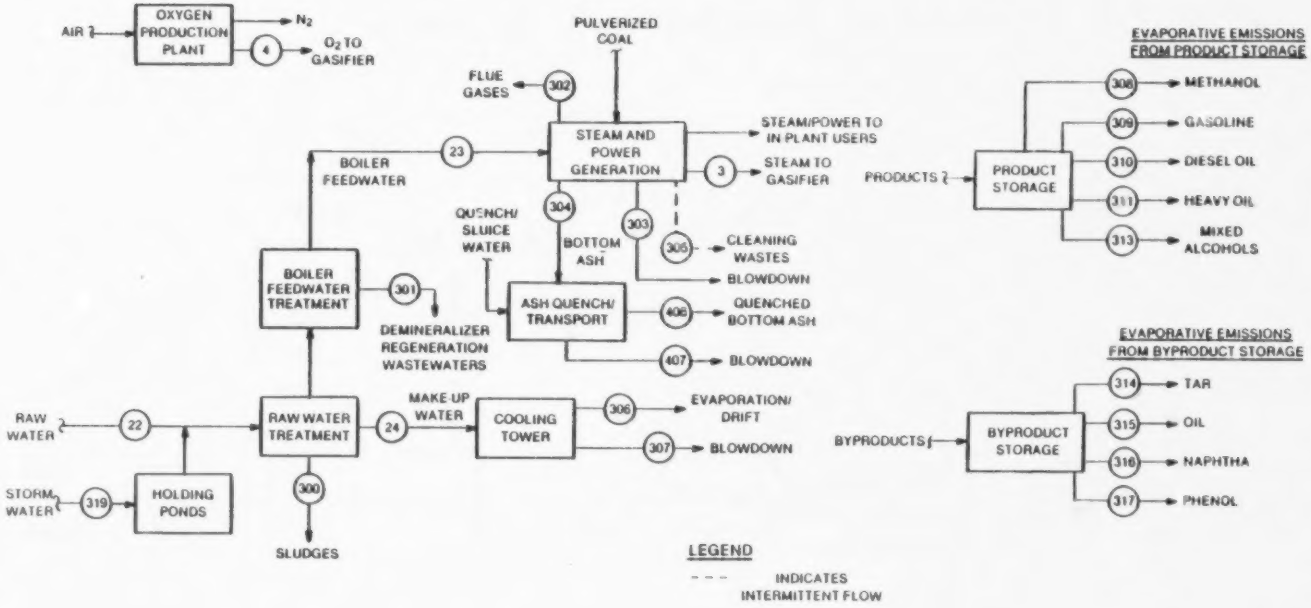


Figure 3-5. Auxiliary processes associated with Lurgi-based synfuels facilities

coal lockhopper gases. Reuse of this stream within the plant is not required to produce the plant's main product(s). Thus, this stream fits the definition of waste stream used in this manual. However, if Lurgi gas is used to pressurize the coal lockhopper, the resulting high pressure coal lockhopper gases should have a composition similar to raw Lurgi gas. As such, these gases would normally be recycled or reused and would not represent a waste stream that would be directed to a pollution control system.

The waste streams identified in this manual can be classified as those that are unique to Lurgi-based facilities and those that are not unique, i.e., waste streams that are commonly generated by other industrial plants in the U.S. In general, the unique streams are produced from the main gasification train, while the nonunique streams are produced predominantly by the auxiliary processes, coal preparation, and refinery type product upgrading. Emphasis in this manual is on the identification/characterization of the unique waste streams and on the presentation of pollution control information for those unique streams. As a result of this emphasis, the depth of treatment and presentation of information for unique waste streams is greater than that for nonunique streams.

In order to provide consistency in the presentation of process and waste stream information, calculated material flows were developed for the base plants, i.e., process configuration and coal feed combinations, examined in this manual. These material balances are for facilities capable of producing approximately 120 TJ/day of synthesis feed gas for the SNG, methanol, Fischer-Tropsch, and Mobil M-gasoline synthesis operations. These size facilities will gasify, depending on the coal feed, from 5800 to 9600 Mg/day of coal and produce, depending on the coal feed and synthesis process used, the energy equivalent of 2900 to 3100 m^3/day of gasoline. Table 3-1 presents a summary of typical upgraded product slates for the synfuels facilities examined. A complete summary of the base plant material balances developed is contained

TABLE 3-1. TYPICAL UPGRADED PRODUCT SLATES FOR LURGI-BASED SYNTHETIC FUELS FACILITIES

Product	SNG Synthesis	Methanol Synthesis	Mobil M-Gasoline	Fischer-Tropsch
SNG	100	54	55	65
C_3 LPG	-	-	2	2
C_4 LPG	-	-	3	<1
Methanol	-	49	-	-
Gasoline	-	-	37	22
Diesel Oil	-	-	-	4
Heavy Fuel Oil	-	-	-	1
Mixed Alcohols	-	-	-	3
TOTAL PRODUCTS	100	103	97	97

Note: All units are TJ/day. Product slates shown are based on gasifying 142 TJ/day of Rosebud subbituminous coal to produce a synthesis gas feed of approximately 120 TJ/day. In addition to the indicated products, the following quantities of byproducts are produced regardless of synthesis process: Naphtha - 2.0 TJ/day; Tars - 5.5 TJ/day; Oils - 5.9 TJ/day; and Phenols - 1.1 TJ/day. Similar quantities of products and byproducts result from use of the other coals examined in this PCTM (See Appendix E).

in Appendix E. For illustrative purposes, the material flow calculations based on gasifying a subbituminous coal (Montana Rosebud) are presented in this section. Stream numbers used in the material balances in Appendix E and throughout the rest of this manual refer to the numbers indicated in the various flow diagrams presented in this section and summarized in Table 3-49.

The operations which comprise a Lurgi-based synfuels facility are discussed in Sections 3.1 through 3.4. At the end of each of these sections is a discussion of the waste streams generated by the operation. Section 3.5 presents information on the characteristics of the products and byproducts expected to be produced by the subject facilities. Sections 3.6 and 3.7 contain, respectively, information on auxiliaries and fugitive type wastes.

The last part of this section (Section 3.8) contains a stream index and summarizes the waste streams identified previously and indicates, for each waste stream, the part of Section 3 where characterization data can be found and the part of Section 4 where pollution control information is presented. Similar type information is also provided for secondary waste streams, i.e., those which originate from a pollution control process which could be utilized in a Lurgi-based synfuel facility.

Numerous references are included in this section to indicate the source of data presented. Additional data (with references) is presented in Appendices A and B for the Lurgi gasification process and Rectisol acid gas removal process, respectively.

3.1 COAL PREPARATION

The coal preparation operation in a Lurgi-based synfuels facility will be similar to the coal preparation operation found in other coal-based plants such as coal-fired power plants. In addition, the waste streams generated by this operation and the processes available to control them will also be similar. Because of the nonuniqueness of coal preparation, limited characterization data are provided. The major focus of this manual is on those waste streams unique to Lurgi-based synfuels facilities.

Feed coal preparation for Lurgi gasification consists mainly of crushing and screening of run-of-mine (ROM) coal to obtain the proper size range. A coal dryer would be included if the feed coal moisture content is greater than about 40 percent, the practical limit for efficient operation of a Lurgi gasifier. Since all three of the coals examined in this manual (see Table 2-1) contain less than 40 percent moisture, a coal dryer is not required.

Depending on the properties of the coal, a Lurgi gasifier can accept a sized coal within the range of 0.3 cm to 7.5 cm. A size range of 0.64 cm to 3.8 cm is used in this manual as a generalized example. A typical arrangement of the coal preparation operation, depicted in Figure 3-6, includes inactive and active coal storage; crushing, screening, and storage of sized coal for gasification; and storage of fine coal with subsequent pulverization for boiler firing. Table 3-2 summarizes the estimated quantities of sized coal required by the Lurgi gasifiers to produce approximately 120 TJ/day of synthesis gas. Also shown in the table are 1) the quantities of ROM coal which must be processed and 2) the quantities of coal fines expected to be generated (before boiler fuel demands are satisfied) to produce the indicated quantities of sized gasifier feed coal. If the boiler fuel demands exceed the available quantity of coal fines, then either additional ROM coal would need to be processed or other sources of boiler fuel (such as Lurgi byproduct hydrocarbons)

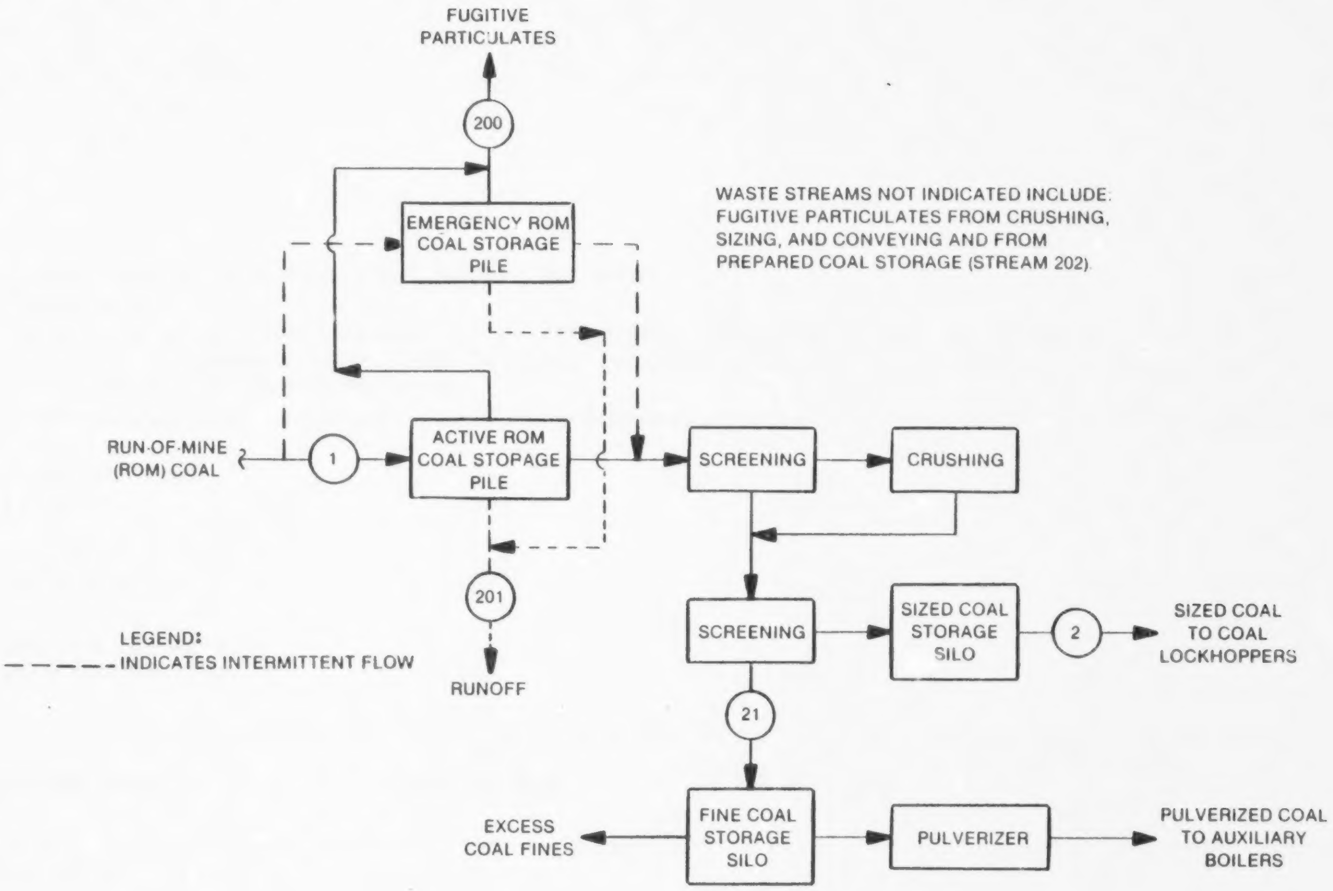

FUGITIVE PARTICULATES
200
EMERGENCY ROM COAL STORAGE PILE
WASTE STREAMS NOT INDICATED INCLUDE: FUGITIVE PARTICULATES FROM CRUSHING, SIZING, AND CONVEYING AND FROM PREPARED COAL STORAGE (STREAM 202).
RUN-OF-MINE (ROM) COAL
1
ACTIVE ROM COAL STOPAGE PILE
SCREENING
CRUSHING
201
RUNOFF
LEGEND:
INDICATES INTERMITTENT FLOW
SCREENING
SIZED COAL STORAGE SILO
2
SIZED COAL TO COAL LOCKHOPPERS
21
EXCESS COAL FINES
FINE COAL STORAGE SILO
PULVERIZER
PULVERIZED COAL TO AUXILIARY BOILERS

Figure 3-6. Simplified block flow diagram of coal preparation

TABLE 3-2. ESTIMATED OVERALL MATERIAL FLOWS FOR COAL PREPARATION OPERATION[a]

Stream No.	1	2	21
Stream Name	Run-of-Mine Coal[b]	Sized Gasifier Feed Coal	Coal Fines[c]
Subbituminous Coal (Montana Rosebud)	456	296	160
Bituminous Coal (Illinois No. 6)	350	242	108
Lignite (Dunn Co., ND)	571	400	171

[a] See Figure 3-6. Units are Mg/hr.

[b] Based on coal needed to satisfy gasifier feed requirements. If quantity of coal fines generated is insufficient to meet boiler demand, additional ROM coal could be processed.

[c] Before auxiliary boiler fuel demands are met.

would need to be used. The following discussions assume that the coal fines generated as a result of preparing the required gasifier feed are sufficient to meet the auxiliary boiler fuel demands.

ROM coal (Stream 1) is received from the mine via trucks, unit trains, barges, or conveyors. It is initially stored in an active storage pile (nominally containing a five-day supply of coal) which provides the feed to the preparation unit. Raw coal is also kept in an emergency storage pile (containing a 30 to 60 day supply). The emergency pile is utilized when the coal supply from the mine is interrupted for an extended period. The storage pile capacity estimates for the base plants presented in this manual are shown in Table 3-3.

TABLE 3-3. ESTIMATED ROM COAL STORAGE PILE CAPACITIES

	5-Day Active Storage Pile	30-Day Emergency Storage Pile
Subbituminous Coal (Montana Rosebud)	55,000	330,000
Bituminous Coal (Illinois No. 6)	42,000	250,000
Lignite (Dunn Co., ND)	68,000	410,000

Units are Mg.

ROM coal, with a nominal top size of 10.2 cm is transported to the coal preparation plant by belt conveyors, where it is screened to make a size separation at about 3.8 cm. The oversize 10.2 cm x 3.8 cm coal from the screens is conveyed to crushers where it is reduced to 3.8 cm top size. The undersize from the screens and the crushed coal from the crushers are then further sized at about 0.64 cm. The 3.8 cm x 0.64 cm coal fraction (Stream 2) is conveyed to the sized coal storage silos, while the undersize 0.64 cm x 0 coal (Stream 21) is conveyed to fine coal storage silos.

Coal required for the steam boiler is withdrawn continuously from the fine coal storage silos, pulverized to 70 percent minus 0.075 mm in a pulverizer, and fed to the boiler. If excess 0.64 cm x 0 coal fines remain after the boiler fuel requirements are met, these can be sold as a byproduct, combusted to produce electricity or steam for export, gasified (in a gasifier which can use coal fines) to produce additional synthesis gas, disposed of as a waste, or possibly pelletized to make a suitable feed for the Lurgi gasifiers.

Waste streams from the coal preparation operation include particulate emissions from ROM coal storage (Stream 200), runoff from ROM coal storage (Stream 201), and particulate emissions from crushing, screening, transfer, and prepared coal storage (Stream 202). The estimated quantities of fugitive particulates originating from the active and emergency storage piles are listed in Table 3-4. These values were calculated using several methodologies that have been developed for estimating such emissions (14). Data on the composition of particulate emissions produced by coal storage piles are becoming available through source test and evaluation studies sponsored by the EPA (15,16).

Data on the characteristics of runoff streams originating from ROM coal storage piles for the subject coals are not currently available. However, laboratory leaching tests with raw coal refuse materials have indicated that the types and quantities of pollutants released from coal storage piles are similar to those produced by coal refuse piles (17). In addition, there are some data available on actual effluents produced by high-sulfur coal storage

TABLE 3-4. ESTIMATED FUGITIVE PARTICULATES FROM COAL STORAGE PILES[a]

	Reference for Emission Estimate	Emissions for Various Coal Feeds, kg/day[b]		
		Subbituminous (Montana Rosebud)	Bituminous (Illinois No. 6)	Lignite (Dunn Co., ND)
Active Storage Pile				
Wind Erosion	12	18	15	24
Loading Activities	13	260	120	160
Vehicular Activities	13	5	3	5
Total (of Above Items)		283	138	189
Total (From Other Reference)	12	170	110	230
Emergency Storage Pile	12/14[c]	120/190	85/120	150/240

[a] See Table 3-3 for estimated coal storage pile capacities.

[b] With no controls applied.

[c] First reference is for first value shown; second reference is for second value.

piles (17). This information, coupled with the known composition of the subject coals, allows qualitative and semi-quantitative estimates to be made of the composition of the storage pile runoff produced by the three coals.

Runoff from storage piles of Midwestern coals (such as Illinois No. 6) is expected to be highly acidic, with pH values in the range of 2 to 4. Total suspended solids during storm runoff can be as high as 2,300 mg/L. Sulfate concentrations may be in excess of 9,000 mg/L. Iron concentrations can range from 23 to 1,800 mg/L, while manganese concentrations can be in the range of 1.8 to 45 mg/L. Other elements expected to be present in the coal pile runoff include aluminum, mercury, arsenic, and zinc (17).

Runoff from the subbituminous coal and lignite storage piles is expected to be close to neutral, with a pH slightly above 7. Sulfate concentrations are expected to be less than 1,000 mg/L. Iron and manganese concentrations are expected to be low, less than 0.8 mg/L for iron and below 0.4 mg/L for manganese (18). The dominant water contaminants are expected to be calcium and magnesium, with concentrations in the ranges of 200 to 400 mg/L and 50 to 250 mg/L, respectively (19). Total suspended solids levels will probably be higher than those present in Illinois No. 6 runoff because of the tendencies of these coals to slake.

Published data on particulate emissions from coal preparation operations are limited. Generally, particulate emission estimates are based upon data taken from surface coal mining and ore mining operations, stone and rock crushing, and coke production. Furthermore, reported emission factors (13,20) for specific operations within preparation plants are based on estimates rather than actual data. It is commonly reported that "western coals and lignites...have several times as much dust as comparable tonnages of eastern coal" (21).

Table 3-5 summarizes uncontrolled fugitive particulate emission factors for several, but not all, activities within the coal preparation operation (13). Applying these factors to the estimated coal flow rates in the coal preparation plant gives the following estimates of uncontrolled fugitive particulate emissions:

subbituminous coal - 3000 kg/day
bituminous coal - 2400 kg/day
lignite - 3900 kg/day

TABLE 3-5. FUGITIVE PARTICULATE EMISSION FACTORS FOR COAL PREPARATION OPERATIONS[a]

Activity	Uncontrolled Emission Factor, kg/Mg handled
Loading From Storage	0.05
Transfer and Conveying	0.10
Secondary Crushing/Screening	0.08

[a] Reference 13.

3.2 LURGI GASIFICATION

The dry ash Lurgi gasifier is a water-jacketed, medium pressure (2.1 to 3.2 MPa), moving-bed gasification system which operates below coal ash fusion temperatures. Essentially all types of coals, with moisture contents below about 40 percent, can be gasified without drying. A single 4 meter diameter Lurgi gasifier processes about 700 to 1000 Mg of coal per day depending on coal quality. Caking coals require a coal distributor equipped with a stirrer and result in reduced throughput rates. As shown in Figure 3-7, the Lurgi gasification unit consists of the following components: coal bunker; coal lockhopper; water-jacketed, pressure gasifier vessel; and ash lockhopper. Although not shown in Figure 3-7, an ash quench system is also generally considered a part of the gasification unit.

Table 3-6 presents calculated material flows for the Lurgi gasification operation based on gasifying a Rosebud subbituminous coal to produce approximately 120 TJ/day of synthesis gas. This balance was developed from available test data (1,3) and published design information (6) for Lurgi gasification systems. The major source of information used to estimate the required inputs and resulting raw gas composition and flow rate was an experimental test program conducted at Westfield, Scotland using Montana Rosebud coal in a commercial Lurgi gasifier (1). However, estimates of the production of C_3 and C_4 aliphatics were obtained from the Environmental Impact Statement for the ANG Coal Gasification Company North Dakota Project (6). The relative quantities of sulfur species in the raw Lurgi gas were based on the sulfur species distribution found in test programs at the Lurgi-type gasification facility in Kosovo, Yugoslavia (3).

The above data sources were also used to develop the gasification material balances presented in Appendix E for gasifying Illinois No. 6 bituminous coal. These same sources were also used for the Dunn County Lignite balances

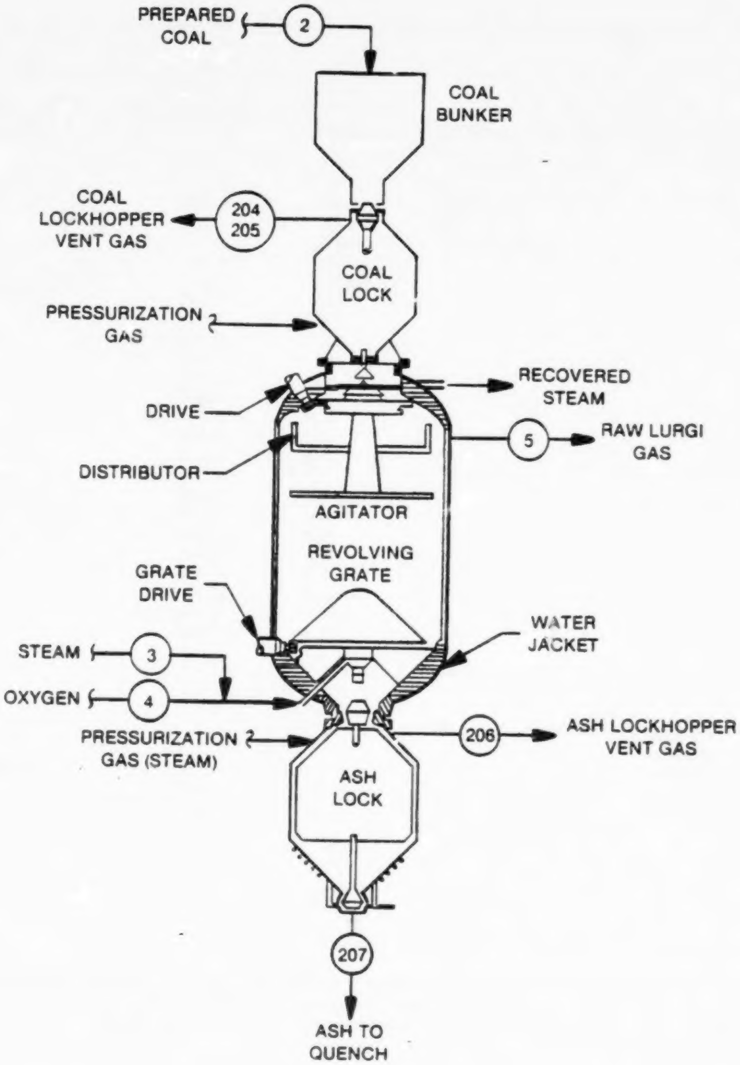


Figure 3-7. Lurgi gasifier

TABLE 3-6. ESTIMATED MATERIAL FLOWS FOR LURGI GASIFICATION OPERATION - ROSEBUD COAL

Stream No.	2	3	4	5	205[a]	207	206
Stream Name	Prepared Coal	Steam	Oxygen	Raw Lurgi Gas	Low Pressure Coal Lockhopper Vent Gases	Gasifier Ash	Ash Lockhopper Vent Gases
kg-moles/hr							
H_2				7,619	4.7		
O_2			2,270	39	0.024		14.3
N_2+Ar			137	162	0.10		0.9
CO				2,806	1.7		
CO_2				5,733	3.5		
CH_4				2,075	1.3		
C_2H_6				92	0.057		
C_2H_4				13	0.008		
C_3H_8				15	0.009		
C_3H_6				13	0.008		
C_4H_{10}				7.4	0.005		
C_4H_8				13	0.008		
C_5^+ aliphatics				8.6	0.005		
Benzene				9.7	0.006		
Toluene				2.3	0.001		
Other aromatics				1.9	0.001		
H_2S				82	0.050		
COS				1.1	0.0007		
CH_3SH				7.2	0.004		
C_2H_5SH				2.3	0.001		
C_3^+ mercaptans				0.3	0.0002		
HCN				1.2	0.0007		
NH_3				137	0.084		
HCl				0.4	0.0002		
Total Dry Gas			2,407	18,843	11.6		15.2
kg/hr							
H_2O	73,210	370,800		293,634	1.7		1550
Coal (MAF)[b]	194,300						
Ash	28,830					30,600	
Particulates				495	0.052		3.5
Organic aerosols					1.9		
Tars				5,710			
Oils				6,181			
Phenols				1,371			
Fatty acids				604			
Other constituents				2,389			
Total, kg/hr	296,340	370,800	77,460	709,664	247	30,600	2043

[a] Assumes Lurgi synthesis gas is used as the lockhopper pressurant. Composition shown excludes ejection air. Composition is also dependent on design and operation of coal lockhopper system.

[b] MAF = moisture and ash free.

Blanks indicate not applicable or no data available.

Number of significant figures shown overstates the accuracy of the calculated estimates.

See Appendix A for details of assumptions and bases.

Not shown in this table are the high-pressure coal lockhopper gases which are expected to be similar in composition to the low-pressure lock-hopper gases.

presented in Appendix E, but greater use was made of information from ANG (6) and Kosovo (3) since these facilities gasify lignite. A more detailed explanation of the bases for the material flow calculations is presented in Appendix A.

The use of Kosovo data (3) to estimate the relative distribution of sulfur species in raw Lurgi gas and the use of ANG data (6) to estimate the production of C_3 and C_4 aliphatics in raw Lurgi gas require a special note. The Kosovo data, which are for lignite gasification, indicate that approximately 10 percent of the gaseous sulfur species appear as non-H_2S compounds with a large portion being mercaptans, especially methylmercaptan. For this test program, special sampling and analytical procedures were used to enable mercaptans to be detected and quantified. The Westfield data (1) for gasifying Rosebud and Illinois No. 6 coals indicate non-H_2S species as being a much lower percentage (2 to 6 percent) of the total gaseous sulfur species. No breakdown of the composition of the non-H_2S species was given in the Westfied data.

The exact mechanisms by which mercaptans, as well as other sulfur species are generated and destroyed in a Lurgi gasifier are not well documented. If gas phase equilibrium exists between the sulfur species, then the assumption of a constant relative sulfur species distribution seems reasonable. On the other hand, kinetic limitations may severely impede the rate of attaining equilibrium. If so, then the mechanism by which each sulfur species is initially created when the coal is gasified becomes most important, and the relative distribution of sulfur species could be mainly a function of coal type and gasifier operating conditions.

The importance of this issue is that non-H_2S sulfur species can impact the performance and costs of controls for acid gases generated in the Rectisol unit. Section 4.1.1 discusses the impacts that non-H_2S sulfur species, and especially mercaptans, have on the performance and costs of reduced sulfur species control technologies.

The quantities of C_3 and C_4 aliphatics produced in a Lurgi gasifier can also impact the performance and costs of controls for acid gases generated in the Rectisol unit. These components, as well as part of the C_2 aliphatics, are expected to be removed from the Rectisol feed gas and appear for the most part in the acid gas stream(s) produced when the Rectisol sorbent is regenerated. Depending on the levels of these components in the Rectisol feed gas, extra costs could be incurred to remove/destroy the aliphatics in the acid gas waste stream(s).

The production of C_3 and C_4 aliphatics depends on, among other factors, the type of coal gasified. Thus, use of a constant production rate of these components based on ANG data for lignite gasification (6), could be an overestimation or underestimation for other types of coal (or even other lignites).

Sections 3.2.1 through 3.2.4 discuss the Lurgi gasification operation and its associated process and waste streams.

3.2.1 Coal Feeding

Sized coal (Stream 2) from the coal preparation operation is stored at atmospheric pressure in a coal bunker located directly above the Lurgi gasifier. Coal is fed from the bunker to the pressurized gasifier vessel in a cyclic manner using a coal lockhopper. At the start of each charging cycle, the coal lockhopper is at nominally atmospheric pressure and is filled with residual gases from the prior charging cycle. As the lockhopper is charged with coal, a portion of these residual gases (Stream 205) are displaced and ejected with air, generating a waste stream. When the desired quantity of coal is obtained in the lockhopper, it is isolated from the coal bunker and pressurized to the gasifier operating pressure using either raw or cooled Lurgi gas or an inert gas such as N_2 or CO_2.

Once pressurized, valves between the lockhopper and gasifier are opened, allowing the coal to flow by gravity into the gasifier. Raw Lurgi gases from the top of the gasifier backflow into the lockhopper in order to fill the space originally occupied by the coal unless additional lockhopper pressurant is added as the coal is dropped. After the complete coal charge has been dropped, the lockhopper/gasifier valves are closed and the lockhopper is depressurized. The resulting depressurization gases are termed high pressure lockhopper gases. Low-pressure-residual lockhopper gases are displaced by the next charge of coal and ejected from the feeding chute with air.

The cycle time of the coal lockhopper is a direct function of the desired gasifier feed rate, and can range from 10 to 30 minutes (7,10). Waste streams generated by the coal feeding process include high-pressure lockhopper gases (Stream 204) and air ejected low-pressure vent gases (Stream 205).

3.2.2 Lurgi Gasification

Coal enters at the top of the Lurgi gasifier, falls on the coal bed, and slowly moves downward, countercurrent to gas flow. As the coal descends, it passes through four "zones" of progressively higher temperature before exiting the bottom of the gasifier as ash. The zones are, from top to bottom, drying, devolatilization, gasification, and combustion. Major chemical reactions associated with these zones are:

$$\text{Coal} + \text{heat} \rightarrow CH_x + H_2O \qquad \text{(drying and devolatilization)}$$

$$C + H_2O + \text{heat} \rightarrow CO + H_2$$
$$C + CO_2 + \text{heat} \rightarrow 2\ CO \qquad \text{(gasification)}$$
$$C + 2H_2 \rightarrow CH_4 + \text{heat}$$

$$C + 1/2O_2 \rightarrow CO + \text{heat}$$
$$C + O_2 \rightarrow CO_2 + \text{heat} \qquad \text{(combustion)}$$

In the first zone, the coal is dried by contact with the hot raw gas leaving the gasifier. As the temperature of the coal rises in the second and third zones, devolatilization and gasification reactions occur. On an overall basis, the reactions in the first three zones are endothermic. Heat for the reactions in these zones is supplied by the combustion reactions which occur in the fourth zone. A revolving grate at the bottom of the gasifier provides for a uniform flow of ash to the ash lockhopper and continuous introduction of steam and high purity oxygen under the downward moving coal bed.

Steam and oxygen requirements for a Lurgi gasifier range from 1.5 to 3.1 and 0.2 to 0.6 kg per kg of MAF (moisture- and ash-free) coal, respectively, depending on the type of coal gasified. Input rates must be suitable to maintain the gasifier combustion zone temperature below the ash fushion temperature. If this temperature is exceeded, clinker or slag formation can occur and result in plugging or destruction of the revolving ash grate located at the bottom of the gasifier. On the other hand, the combustion zone temperature must not be so low that the gasification reactions are impaired. The combustion zone temperature is adjusted by varying the ratio of steam to oxygen.

The hot raw Lurgi gas leaving the gasifier (Stream 5) is composed primarily of unreacted steam, methane, carbon monoxide, carbon dioxide, and hydrogen. Also present are low molecular weight hydrocarbons (C_2H_4, C_2H_6, C_3-C_6), benzene, toluene and other aromatics, higher molecular weight organics (e.g., tars, oils, phenols, fatty acids), reduced sulfur and nitrogen compounds (e.g., H_2S, COS, mercaptans, NH_3, HCN), and entrained coal particles. Table 3-7 summarizes the concentrations of major and minor components expected in raw Lurgi gases. In addition to the components shown, heavy hydrocarbons (i.e. tars, oils, and phenols), entrained particulate matter, and trace elements are expected to be present in the raw gases. On a moisture-free basis, the concentrations of major components in the raw gas are relatively independent of the feed coal type (approximately 40% H_2, 16% CO, 30% CO_2, 10% CH_4, and 1% nonmethane organics). The levels of other components (including nitrogen-containing compounds, trace elements, and organics), in contrast, can vary significantly with the specific coal.

3.2.3 Ash Removal

Ash is removed from the Lurgi gasifier via a lockhopper which is pressurized with steam. The lockhopper discharges into an ash quench basin or sluice launder. In either case, the quenched ash slurry which results is sent to a series of vibrating screens and classifiers where large ash particles are separated. The remaining ash quench water contains approximately one percent (by weight) ash fines and is pumped to thickeners and dewatering ponds for settling. Clarified overflow from the thickeners and ponds is recycled, along with makeup quench water, to the quench basin or sluice launder. Water is lost from the ash quenching system due to vaporization (the hot ash (Stream 207) is initially discharged at approximately 530 K) and evaporation from the dewatering pond. Figure 3-8 depicts a generalized gasifier ash quench system.

Waste streams generated by the ash removal process include ash lockhopper depressurization vent gases (Stream 206), evaporation from ash quenching, and quenched gasifier ash (Stream 403).

TABLE 3-7. ESTIMATED MAJOR AND MINOR COMPONENTS OF RAW LURGI GAS[a,b]

	Subbituminous Coal (Montana Rosebud)	Bituminous Coal (Illinois No. 6)	Lignite (Dunn Co., ND)
H_2, vol. %	40.4	37.6	38.8
CO, vol. %	14.9	17.2	15.6
CO_2, vol. %	30.4	31.6	31.7
CH_4, vol. %	11.0	9.5	10.8
N_2+Ar, vol. %	0.86	1.2	0.84
O_2, vol. %	0.21	0.11	NA
Aliphatics, vol. %	0.87	0.85	1.0
Aromatics, vol. %	0.074	0.11	0.41
H_2S, ppmv	4400	9100	4000
Other Reduced Sulfur Species, ppmv	580	1200	530
HCN, ppmv	60	60	60
NH_3, ppmv	7300	7400	4100

[a] References 1, 3, and 6.

[b] Also present in raw Lurgi gas are high molecular weight organics (such as phenols, tars, oils), entrained particulate matter, and trace elements.

NA = data not available.

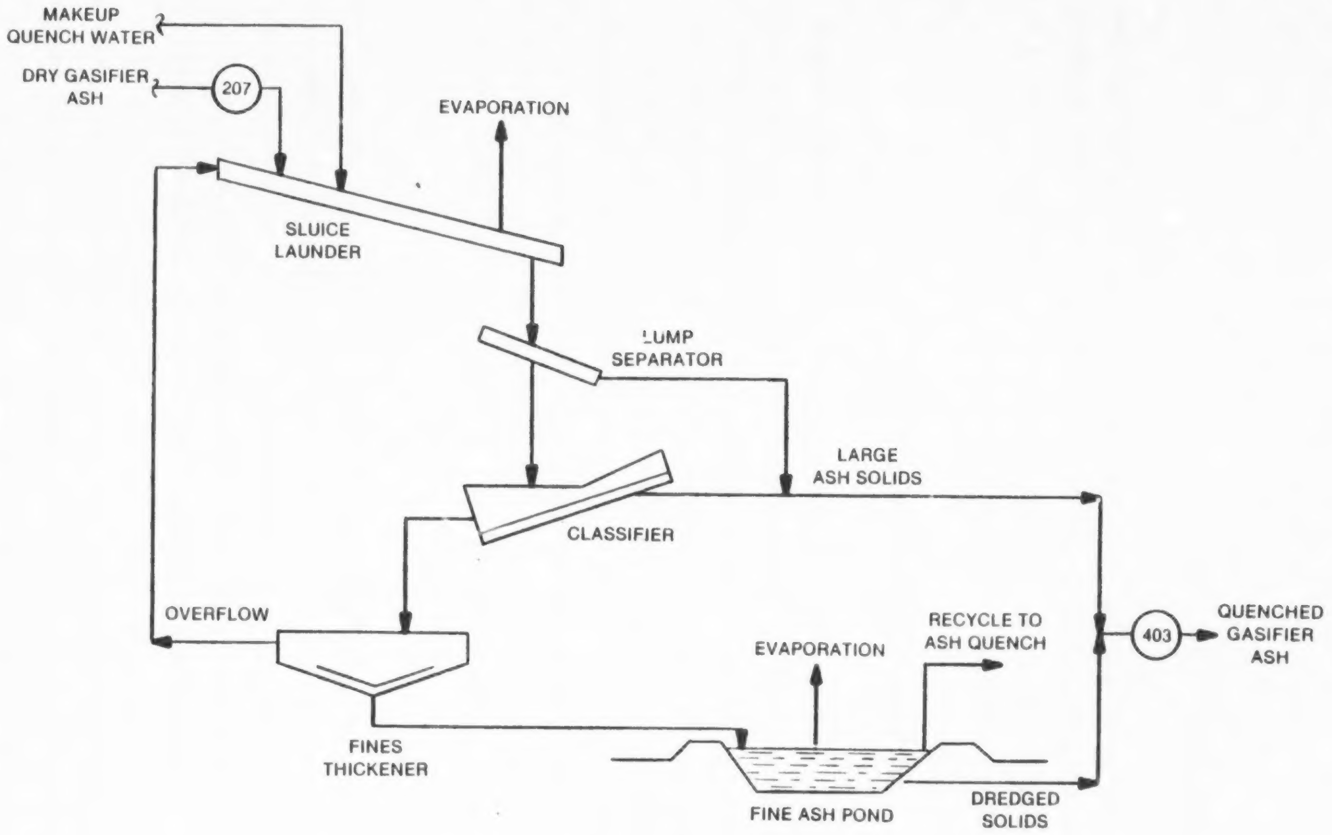


Figure 3-8. Schematic of ash quench system for Lurgi gasification

3.2.4 Waste Stream Characteristics

Waste streams generated by the Lurgi gasification operation include: 1) high pressure (Stream 204) and low pressure (Stream 205) coal lockhopper gases, 2) transient waste gases (Stream 208), 3) ash lockhopper vent gases (Stream 206), and 4) quenched gasifier ash (Stream 403).

Coal Lockhopper Vent Gases (Streams 204 and 205)

Characteristics of the coal lockhopper gases are determined largely by the gas used to pressurize the lockhopper. Raw or cooled Lurgi gas or an inert gas such as CO_2 or N_2 can be used, but the most commonly proposed design uses cooled Lurgi gas for pressurization. In this design, approximately 98% of the gases produced when the lockhopper is depressurized (high-pressure lockhopper gases; Stream 204) are collected, compressed, and recombined with the raw Lurgi gases. Low-pressure residual gases which cannot be recycled (Stream 205) are ejected with air in conventional designs. Due to the nature of the lockhopper operation, the lockhopper vent gases are generated on an intermittent basis.

Whether Lurgi gas or an inert gas is used to pressurize the coal lockhoppers, the residual lockhopper gases are expected to contain the same constituents as found in the raw Lurgi gas (Stream 5). This is expected because raw Lurgi gases will enter the lockhopper, after the coal is dumped, to fill the space originally occupied by the coal. The resulting lockhopper gases will thus be a mixture of raw Lurgi gases and the lockhopper pressurant gas. If an inert gas is used as the lockhopper pressurant, the amount of raw gases which enter the lockhopper can be minimized or possibly eliminated if a positive flow of pressurant gas is maintained as the coal charge is dumped.

If Lurgi gas is used as the pressurant, the coal lockhopper gases (both low- and high-pressure) should resemble the composition shown in Table 3-6 for raw Lurgi gas. In addition to the components shown in this table, test data indicate that entrained coal particles and aerosol organics (basically condensed tars and oils) will be present (3). The concentrations of these components are estimated at 0.2 g/Nm^3 and 7.3 g/Nm^3, respectively. These estimated concentrations are based on data from the Kosovo gasification plant where raw Lurgi gases are used to pressurize the coal lockhoppers (3). At the Kosovo plant the low-pressure lockhopper gases are those below 0.2 MPa. Lowering this cutoff pressure between high- and low-pressure gases can not only reduce the quantity of low-pressure gases generated, but also can help reduce the concentrations of entrained coal particles and aerosol organics in the residual low-pressure gases (2). The reader should remember that the design features and operating procedures for coal lockhoppers can affect the composition of coal lockhopper vent gases. Therefore, modern Lurgi designs may result in a different coal lockhopper vent gas composition than that observed at Kosovo.

If an inert gas is used as the lockhopper pressurant the same components shown in Table 3-6 are expected to be present. However, their concentrations are expected to be decreased due to the dilutive effect of the inert gas.

The volume of coal lockhopper vent gases generated has been estimated using data for the ANG Lurgi-based SNG facility (7). For that plant, low pressure residual lockhopper gases are reported to be approximately 37 kg-moles/hr, before dilution with ejection air. The lignite feed rate for the ANG plant is about 1020 Mg/hr. Assuming that the lockhopper gases generated are proportional to the coal feed rate, a factor of 0.04 kg-moles of low pressure vent gas per Mg coal feed is calculated. Information for the ANG plant (7) also indicates that the low-pressure residual lockhopper gases represent 2 percent of the total volume of lockhopper gases generated (excluding ejection air). Thus, the volume of high-pressure coal lockhopper gases is approximately 49 times the volume of the low-pressure gases. The calculated flow rates of low- and high-pressure lockhopper gases are summarized below. Again, flow rates shown are exclusive of ejection air. Including this ejection air, as well as dilution air required to reduce explosion hazards (see Section 4.1), could increase the flow rate of the low pressure gases by a factor of 20 or more (7). Of course pollutant concentrations would be reduced by a similar factor.

	Low-Pressure Gases	High-Pressure Gases
Subbituminous Coal	12 kg-moles/hr	570 kg-moles/hr
Bituminous Coal	9 kg-moles/hr	460 kg-moles/hr
Lignite	15 kg-moles/hr	740 kg-moles/hr

Transient Waste Gases (Stream 208)

Raw gasifier outlet gases produced during startup, shutdown, and upset conditions are not suitable for synthesis use and constitute a gaseous waste stream. The following is assumed to be representative of the frequency of generation and volume of transient waste gases generated by the Lurgi-based synfuels facilities examined in this manual. These estimates, which are based on data submitted for the ANG facility (7) and reported to be worst case estimates for unscheduled hot startups, are for facilities using approximately twelve gasifiers.

Type of Maintenance	Type of Startup	Duration of Startup (hr)	Number Per Year	Waste Gas Generation Rate per Startup, kg-moles/min
Scheduled Overhaul	Cold	8	13	11
Unscheduled:				
Long	Cold	8	26	11
Short	Hot	1	104	19

Additional information for the ANG facility (7) indicated transient waste gases associated with worst case plant operating conditions are assumed to occur when two gasifiers are in the "cold" startup mode and one gasifier is in the "hot" startup mode. Under these conditions waste gases would be generated at a rate of about 42 kg-moles/min. Based on the schedule given above, the annual quantity of transient gases is estimated as approximately 330,000 kg-moles.

The composition of transient waste gases is expected to vary considerably over the duration of the startup. For analysis purposes, it is assumed that the composition of the transient waste gases is approximately that of raw Lurgi gases generated by gasification using air as the source of oxygen for the gasifier (see Table 3-8). This should be a reasonable assumption since gasifiers are commonly "cold started" with air rather than oxygen, and it is this type of transient operation which is expected to account for the bulk of the generated transient gases.

In addition to the components shown in Table 3-8, transient waste gases will also contain entrained particulate matter and aerosol organics. The concentrations of these components after the transient gases have been subjected to a quenching step are estimated at 0.06 and 9 g/Nm^3, respectively, based on data from the Kosovo gasification plant (3). Like raw Lurgi gas and coal lockhopper gases, the aerosol organics in transient gases contain polycyclic organic material (POM) similar to that found in the byproduct tars and oils (22). Table 3-9 summarizes the POM components identified in Kosovo byproduct tars and oils (3).

TABLE 3-8. ESTIMATED COMPOSITION OF AIR-BLOWN LURGI GASES[a] (7)

Component	Volume % Wet Basis
H_2	16.8
CO	6.7
CO_2	15.0
CH_4	5.1
N_2	28.1
H_2S	0.2
NH_3	0.4
H_2O	27.7

[a] Gasifier startup gases are assumed to be of similar composition.

TABLE 3-9. POLYCYCLIC ORGANIC MATTER IDENTIFIED IN KOSOVO BYPRODUCT TARS AND OILS (3)

Component	Concentration (mg/kg) in	
	Light Tar	Medium Oil
Benz(a)anthracene	490	160
7,12-dimethylbenz(a)anthracene	1,100	62
Benzo(b)fluoroanthrene	310	120
Benzo(a)pyrene	210	68
Dibenzo(a,h)anthrene	23	6.6
3-Methylcholanthrene	26	<1

Ash Lockhopper Vent Gases (Stream 206)

Steam is utilized for pressurization of the ash lockhopper to avoid the flow of gasifier feed (i.e. steam and O_2) from the gasifier into the ash lockhopper. Before ash is discharged from the lockhopper to the ash quench system, it is depressurized. The resulting vent gases should contain essentially only steam, minor amounts (less than 1 percent) of O_2, and entrained ash particles (2). The only test data available on ash lockhopper vent gases is for the Kosovo plant (3). At this plant, the ash lockhopper gases are sent to a cyclone where they are contacted with process water (the source of the process water was not known). The cyclone exit gas contained 85 percent moisture and had the following composition on a dry basis (3):

Component	Concentration
O_2	48%
N_2	35%
CO_2	14%
H_2S	82 ppmv
NH_3	340 ppmv
HCN	54 ppmv
Particulates	10.3 g/m^3

It is not known whether the CO_2, H_2S, NH_3, and HCN originated from the ash lockhopper gases or the process water used to scrub the gases. However, the results obtained are unexpected and probably indicate that the contaminants originated with the process water. For material flow estimating purposes, the ash lockhopper vent gases are assummed, based on Kosovo data (3), to be produced at a rate of 0.016 kg/kg dry ash and contain 85 percent moisture and 10.3 g particulate per Nm^3 of dry vent gas. The dry vent gas was assumed to consist of O_2 and N_2 in the same proportion as found in the oxygen feed (Stream 4).

Quenched Gasifier Ash (Stream 403)

Table 3-10 presents flow rate information for the major streams found in the ash quenching system. The water vaporized during quenching was calculated by assuming that 10 percent of the quench makeup water would be vaporized. The water lost through evaporation from the fine ash pond was calculated as 0.158 kg water per kg dry ash based on data in Reference 10. The quenched ash ready for disposal was assumed to be 20 weight percent water.

Table 3-11 presents data on the expected composition of unquenched gasifier ashes and leachates from these ashes (9,23). There are currently no data publicly available on the characteristics of leachates from quenched Lurgi ash. Since the ash quenching operation is a net consumer of water, constituents solubilized during quenching would ordinarily remain with the wet ash sent to disposal. Hence, the data in Table 3-11 should present a reasonable picture of the leachability of trace elements from quenched gasifier ash assuming no contribution of constituents from quench makeup water. If contaminated process waters are used for ash quenching, it is possible that the ash may become contaminated with water-derived substances which may be subsequently leachable.

TABLE 3-10. ESTIMATED MASS FLOWS FOR GASIFIER ASH QUENCHING SYSTEM

Stream	Flow Rates (kg/hr) Subbituminous (Montana Rosebud)	Bituminous (Illinois No. 6)	Lignite (Dunn Co., ND)
Dry Gasifier Ash	30,600	22,300	28,600
Makeup Water	13,600	9,900	12,700
Water Vaporized during Quench	1,100	830	1,000
Water Evaporated from Dewatering Pond	4,800	3,500	4,500
Ash for Final Disposal (20% water)	38,300	27,900	35,800

TABLE 3-11. COMPOSITION AND LEACHING CHARACTERISTICS OF UNQUENCHED LURGI GASIFIER ASHES

	Rosebud[a]		Illinois No. 6[a]		Dunn County[b]	
Constituent	Ash	RCRA Leachate	Ash	RCRA Leachate	Ash	Leachate
Major Constituents (Wt%-Dry Basis)						
Al_2O_3	17.7	—	20.5	—	24	—
CaO	8.3	—	2.3	—	26	—
Fe_2O_3	11.2	—	20.5	—	11	—
K_2O	—	—	1.8	—	0.6	—
MgO	3.9	—	0.6	—	7	—
Na_2O	—	—	0.3	—	8	—
SiO_2	46.8	—	49.3	—	25	—
TiO_2	—	—	1.0	—	0.6	—
SO_3	1.7	—	1.5	—	3.1	—
C	6.5	—	3.2	—	6.5	—
Cl	0.115	—	0.01	—	0.007	—
Trace Elements (PPM-Dry Basis)						
Ag	0.23	0.0002	0.4	0.001	1	—
As	26	0.003	3	0.004	74	0.03
B	380	1.85	355	0.25	1680	13.36
Ba	1900	2.3	950	0.2	8270	0.37
Be	2.8	—	12	—	6	—
Br	—	—	1	—	3	—
Cd	2.4	0.002	1.6	0.013	0.5	0.001
Ce	—	—	140	—	190	0.009
Co	4.3	—	34	—	13	0.01
Cr	440	0.006	212	0.003	140	0.31
Cs	—	—	11	—	0.9	0.02
Cu	130	0.013	57	0.004	27	0.09
F	600	0.12	10	0.18	191	0.43
Ga	—	—	26	—	53	—
Ge	—	—	7	—	2	—
Hg	0.03	0.004	0.05	0.0005	0.055	0.0001
Li	85	—	42	—	45	0.25
Mo	200	—	30	—	12	0.55
Mn	790	9.25	1859	0.71	760	0.1
Ni	200	0.138	89	—	25	0.02
P	—	—	87	—	3500	0.88
Pb	40	0.002	45	0.002	58	0.01
Rb	—	—	162	—	35	1.03
Sb	6.2	—	4.2	—	33	—
Sc	—	—	20	—	4	0.001
Se	2.2	0.001	1	0.003	0.5	0.009
Sn	3.7	—	—	—	4	—
Sr	—	—	370	—	12,900	—
Te	—	—	—	—	0.3	—
U	13	0.5	17	0.5	7	—
V	91	—	184	—	150	0.39
W	—	—	1.5	—	2	0.024
Y	—	—	—	—	320	—
Zn	32	0.33	400	4.27	10	0.02
Zr	—	—	170	—	520	—

[a] From Reference 23.

[b] Calculated from data in Reference 9. In that study boiler water was used to prepare 10% solids slurries. The slurry elemental concentrations reported were adjusted to the volumes which the RCRA Extraction Procedure would represent.

— indicates not applicable or no data available.

3.3 GAS PURIFICATION AND UPGRADING

Raw Lurgi gases contain a number of impurities which must be removed prior to product synthesis. In addition, for some raw Lurgi gases and/or synthesis operations the composition of the gas must be adjusted to meet the stoichiometric requirements for the synthesis process. The gas purification and upgrading operation accomplishes these objectives by 1) quenching and cooling the raw gases, 2) shifting a portion of the gases to adjust the H_2 to CO ratio, 3) removing CO_2 and reduced sulfur compounds, and 4) removing traces of sulfur compounds.

During purification and upgrading of raw Lurgi gases, the contaminants removed from the gas become components of waste streams. As a result, the purification and upgrading operation generates several of the most important waste streams in Lurgi-based synfuels facilities from the standpoint of stream composition and volume.

Table 3-12 presents calculated material flows for the gas purification and upgrading operation of a Lurgi-based synfuel facility producing approximately 120 TJ/day of synthesis gas from a subbituminous (Montana Rosebud) coal.

3.3.1 Gas Quenching and Cooling

A typical processing sequence for raw gas quenching and cooling in a Lurgi-based synfuels facility is shown in Figure 3-9. As indicated in this figure, raw Lurgi gas (Stream 5) is cooled in several stages. Also indicated in this figure is that shift conversion, if necessary, would typically occur between primary and secondary cooling. Section 3.3.2 discusses shift conversion.

TABLE 3-12. ESTIMATED MATERIAL FLOWS FOR GAS PURIFICATION AND UPGRADING - ROSEBUD COAL

Stream No.	5	209	111	112	210	10	213	216	114	12
Stream Name	Raw Lurgi Gas	Gas Liquor Depressurization Gases	Byproduct Lurgi Tars	Byproduct Lurgi Oils	Gas Liquor	Quenched Lurgi Gas	AGR Offgases	Methanol/ Water Still Bottoms	Byproduct Lurgi Naphtha	Sulfur-Free Synthesis Gas
kg-moles/hr										
H_2	7,619					7,619	23			7,596
O_2	39					39				39
N_2+Ar	162					162	4			158
CO	2,806	1.1				2,805	56			2,749
CO_2	5,733	80			93.3	5,560	4,954			606
CH_4	2,075	3.6				2,071	54			2,017
C_2H_6	93	0.18				93	53			40
C_2H_4	13	0.18				13	7.5			5.5
C_3H_8	15					15	15			0.1
C_3H_6	13					13	13			
C_4H_{10}	7.4					7.4	6.6		0.8	
C_4H_8	13					13	11.5		1.5	
C_5 aliphatics	8.6					8.6	0.9		7.6	
Benzene	9.7					9.7	0.53		9.2	
Toluene	2.3					2.3	0.032		2.27	
Other aromatics	1.9					1.9		0.004	1.9	
H_2S	82	0.93			0.50	81	80.9		0.1	
COS	1.1	0.011				1.1	1.1			
CH_3SH	7.2	0.34				6.9	6.6		0.3	
C_2H_5SH	2.3	0.2				2.1	1.5		0.6	
C_3 mercaptans	0.3	0.027				0.3			0.27	
HCN	1.2	0.005			0.056	1.1	0.54	0.007	0.55	
NH_3	137	2.0			135	0.2	0.15	0.044		
HCl	0.4					0.2		0.19		
Methanol							8.1	0.017		
Total Dry Gas	18,843	88.6				18,526	5,298	0.26		13,211
kg/hr										
H_2O	293,634	85			292,960	576		9,965		
Ash										
Particulates	495		426	12	57					
Tars	5,710		5,665		45					
Oils	6,181			6,181						
Phenols	1,371				1,371					
Fatty Acids	604				604					
Other Constituents	2,389				2,389					
Total, kg/hr	709,664	3,830	6,091	6,193	303,850	388,868	228,219	9,965	1,876	158,451

Blanks indicate not applicable or no data available. Number of significant figures shown overstates the accuracy of the calculated estimates.
See Appendices A and B for details of assumptions and bases.

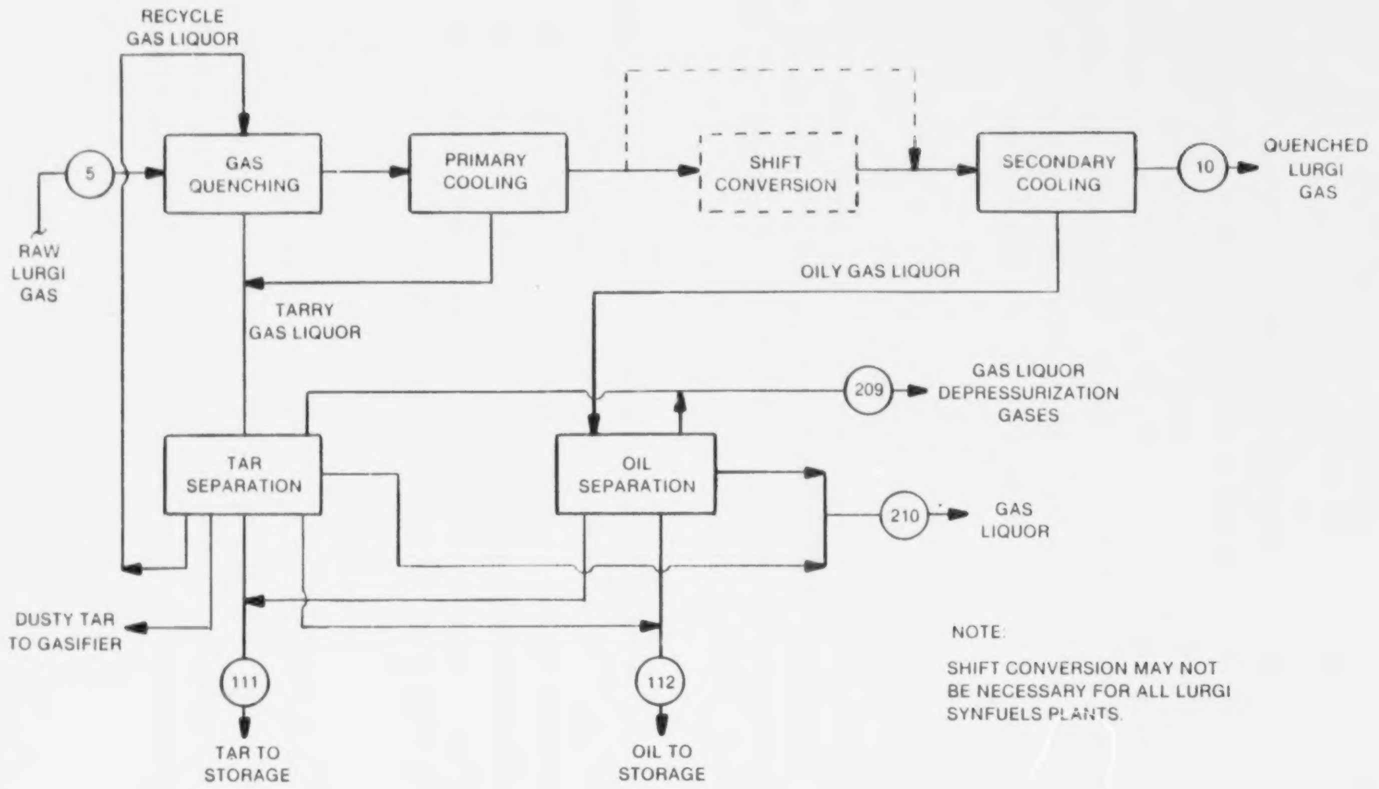


Figure 3-9. Raw gas quenching and cooling system

Raw gas from the Lurgi gasifier is immediately quenched in a direct contact "wash cooler." Quenched gas from the wash cooler undergoes primary cooling in vertical tube waste heat boilers. Secondary cooling, either immediately after primary cooling or after shift conversion, is accomplished in a series of indirect coolers. Energy recovery is normally practiced to the extent possible during the secondary cooling step, but final cooling to about 310 K is accomplished using cooling water and/or air coolers.

Moisture, tars, oils, and phenols are condensed as the raw gas passes through the wash cooler and primary and secondary coolers. The resulting condensate, termed gas liquor, is sent to the gas liquor separation unit. Also present in the gas liquor stream are water soluble components present in the Lurgi gases, including ammonia, carbon dioxide, hydrogen sulfide, and hydrogen cyanide, and dust scrubbed from the raw gas.

The gas liquor separation unit, shown in Figure 3-9 as tar separation and oil separation, actually consists of a series of coolers, depressurization vessels, and gravity separators. These pieces of equipment permit the tars (Stream 111) and oils (Stream 112) to be separated from the aqueous phase of the gas liquor and recovered as byproducts. Dust present in the gas liquor becomes admixed with a portion of the tars. This dusty tar is recycled to the gasifier.

Waste streams produced by gas quenching and cooling come from the gas liquor separation unit and include flashed gases from the depressurization and gravity separation vessels (Stream 209) and gas liquor (Stream 210). The expected characteristics of these waste streams is discussed in Section 3.3.5.

3.3.2 Shift Conversion

The production of synthetic liquids requires a synthesis gas containing H_2 and CO in a ratio of 2 to 1 or higher. For SNG synthesis, the required ratio is 3:1. To obtain the desired H_2:CO ratio, a portion of the Lurgi gases may require shifting, i.e., the reaction of carbon monoxide and water to form carbon dioxide and hydrogen. This reaction is mildly exothermic and can be promoted by a variety of catalysts.

$$CO + H_2O \rightarrow CO_2 + H_2 + \text{heat}$$

In principle, shift conversion may be conducted either prior to or following sulfur species removal. When shift conversion precedes sulfur species removal, moisture (steam) contained in the partially cooled gases can be utilized in the shift reaction. Subsequent acid gas removal steps can deal with CO_2 and H_2S at the same time. However, sulfur tolerant shift catalysts must be employed. Shift conversion after sulfur species removal allows the use of nonsulfur-tolerant catalysts but incurs energy penalties for steam addition. The primary advantage of nonsulfur-tolerant shift catalysts is that a greater degree of carbon monoxide conversion is attainable, which is desirable for pure hydrogen and ammonia production. A separate step for CO_2 removal following nonsulfur-tolerant shift conversion is needed. Shift conversion is thus not readily separable from acid gas removal in terms of overall facility design and operation.

Since raw Lurgi gas contains large amounts of unreacted steam, it is thermodynamically advantageous to conduct shift prior to acid gas removal. Also, a high degree of carbon monoxide conversion is not needed for indirect liquefaction or SNG production. Thus, all proposed Lurgi SNG or indirect liquefaction facilities in the U.S. feature the use of sulfur tolerant cobalt molybdate based catalysts, which are active above about 500 K (5,24).

In most designs, only a portion of the quenched Lurgi gas (Stream 6) would undergo shift conversion. This shifted portion (Stream 8) would then be recombined with the shift bypass stream resulting in a stream with the necessary H_2/CO ratio. The portion of the gas to be shifted will depend on the performance of the gasifier and Rectisol units, the characteristics of the coal, the activity (or age) of the shift catalyst, and the synthesis operation requirements. Although shift conversion can follow acid gas treatment, locating this unit upstream of the acid gas removal unit avoids an additional acid gas treatment step for the removal of the CO_2 generated in the shift reaction.

Figure 3-10 illustrates a typical fixed bed shift conversion process. All steam required for the shift reaction is supplied by moisture contained in the partially-cooled Lurgi gases (Stream 6). The two-reactor configuration serves to control temperatures in the process via feed/product heat exchange.

Available data indicate that cobalt molybdate-based catalysts can also catalyze the hydrolysis of carbonyl sulfide:

$$COS + H_2O \rightarrow H_2S + CO_2$$

Further, mercaptans and hydrogen cyanide can be partially hydrogenated to H_2S and ammonia, respectively, over the catalyst. Olefins and aromatics can also be hydrogenated.

For the three coals examined in this manual, raw Lurgi gases contain H_2 and CO in amounts exceeding the theoretical 2:1 ratio required for methanol (and Mobil M-gasoline) or F-T synthesis. Thus, during steady state operations and assuming CO_2 removal in the Rectisol acid gas removal unit to levels of 1 to 3% in the synthesis feed, no shift conversion would be necessary prior to methanol or F-T synthesis operations. However, to provide flexibility in

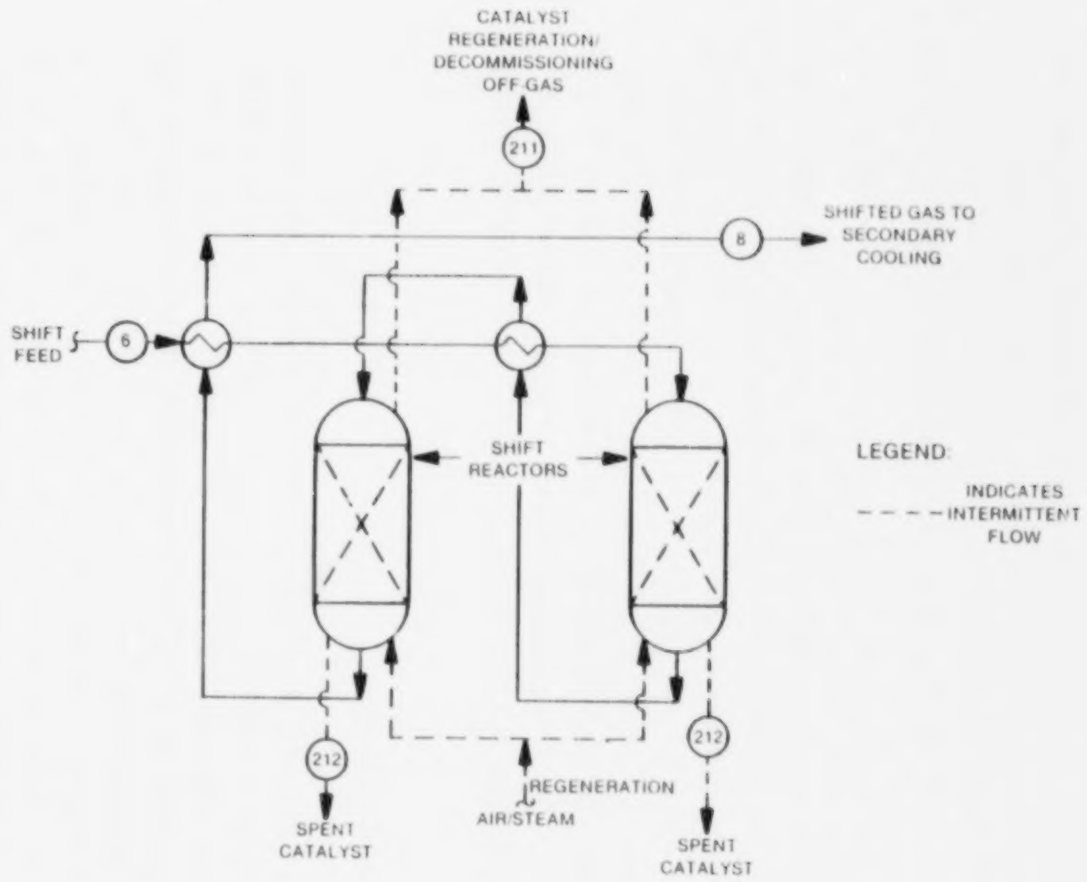


Figure 3-10. High temperature shift conversion

dealing with minor process upsets in either the gasifier or the Rectisol unit, it is expected that shift capacity for about 10 to 20 percent of the raw gas would be provided. For analysis purposes though, no shift conversion is assumed for methanol, Mobil M-gasoline, or F-T synthesis. For SNG synthesis a shift conversion unit will normally always be required to obtain the necessary 3:1 ratio of H_2 to CO.

Shift catalysts in service with hydrocarbon containing gases must be periodically regenerated to remove accumulated coke (carbon) deposits. This is accomplished by steam injection and controlled oxidation with air to burn off carbon (and reduced sulfur). An offgas (Stream 211) is produced containing oxidized sulfur compounds. After a few regeneration cycles, shift catalysts lose activity due to physical degradation or accumulation of chemical poisons and must be replaced. Thus, regeneration/decommissioning offgas and spent shift catalyst (Stream 212) are the wastes from the shift conversion process (see Section 3.3.5).

3.3.3 Rectisol Acid Gas Removal

The removal of H_2S and other sulfur-containing compounds from quenched and cooled (and shifted if necessary) Lurgi gas is required to prevent catalyst poisoning in the synthesis operations. The removal of most of the CO_2 content of the Lurgi gases is necessary to obtain the required synthesis feed gas H_2:CO_x ratio. Although there are many acid gas removal processes currently available, Rectisol is the only process examined in this manual. Rectisol refers to a generic class of refrigerated methanol-based acid gas removal processes which are licensed worldwide by Lurgi Mineraloltechnik GmbH (Frankfurt), Linde AG (Munich), and Krupp Koppers GmbH (Essen). In the U.S., Rectisol is licensed by subsidiaries of the above firms -- Lurgi Corp. USA, Lotepro Corp., and Gesellschaft fur Kohle Technologie mbH (GKT). The Rectisol process was originally developed primarily to treat Lurgi gases. All existing and currently proposed Lurgi-based synfuel facilities feature Rectisol designs by either Lurgi or Linde (Lotepro). The GKT Rectisol license is limited to applications with Koppers-Totzek gasification.

The Rectisol process functions by physically absorbing gaseous components in refrigerated methanol. The components of quenched and cooled Lurgi gas have widely different solubilities in cold methanol. As a result, the Rectisol process can effectively remove gases which are usually considered impurities (such as H_2S and CO_2), but only remove minor amounts of useful gases such as CO, CH_4, and H_2.

The Rectisol process basically consists of three sections. In the prewash section, heavy organics (such as naphtha, high molecular weight sulfur compounds, and gumformers) and water are removed from the inlet gas and processed to recover a byproduct naphtha and an aqueous waste. In the absorption section, sulfur species and CO_2 are removed from the prewashed gas producing an essentially sulfur-free synthesis feed gas. The third section regenerates the acid gas-laden methanol for recycle to the absorption and prewash sections. Offgases from regeneration constitute the major waste stream from the Rectisol process.

There is a great deal of flexibility available in designing a Rectisol unit. Important considerations include the desired composition of the treated synthesis gas, the composition of the gas to be treated, the desired composition of the acid gas waste stream(s) generated, capital investment requirements, operating costs, and energy usage/recovery. In general, Rectisol units can be designed to meet the requirements of almost any application, although some designs may not be economically attractive. Conceptually, Rectisol designs are of two basic types - nonselective Rectisol and selective Rectisol.

These two designs are described below. Important factors which can influence the characteristics of the waste streams generated by either of the two types of Rectisol designs are discussed in Section 3.3.5.

In the nonselective Rectisol process (see Figure 3-11), feed gas (Stream 10) is first cooled to approximately 240 to 250 K. The cooled gas then enters the prewash tower where methanol absorbs water, naphtha, ammonia, and residual heavy organics such as high molecular weight sulfur compounds and gumformers from the raw gas. The solvent leaving the prewash column enters the prewash flash vessel where a flash stream containing H_2S and CO_2 is produced. The liquid bottoms from the prewash flash vessel are routed to a naphtha separator where water is added to separate the naphtha fraction (Stream 114) from methanol/water by phase separation. Residual naphtha, HCN, and sulfur species are stripped from the methanol/water in an azeotrope column. The methanol/water are subsequently separated in a methanol/water still with the methanol-containing offgases from the still unit routed to a hot regenerator and the aqueous still bottoms (Stream 216) sent to wastewater treatment.

After prewash the gas stream enters the main absorber where the bulk of the acid gases are absorbed. Additionally, some hydrocarbons, H_2, and CO are absorbed, as in all physical absorption systems. The rich methanol from the absorber is flashed in several stages. The high pressure flash gas is rich in valuable compounds (e.g., H_2, CH_4, and CO) and is normally recompressed and added to the inlet raw gas or used as a fuel gas. Flash gases from the other stages are predominantly CO_2 and H_2S and are combined with the off-gases from the prewash flash and the hot regenerator. After flash regeneration, the bulk of the methanol is returned to the middle section of the main absorber. The balance of the methanol is regenerated further in a hot regenerator to remove the last traces of absorbed gases. The hot regenerated

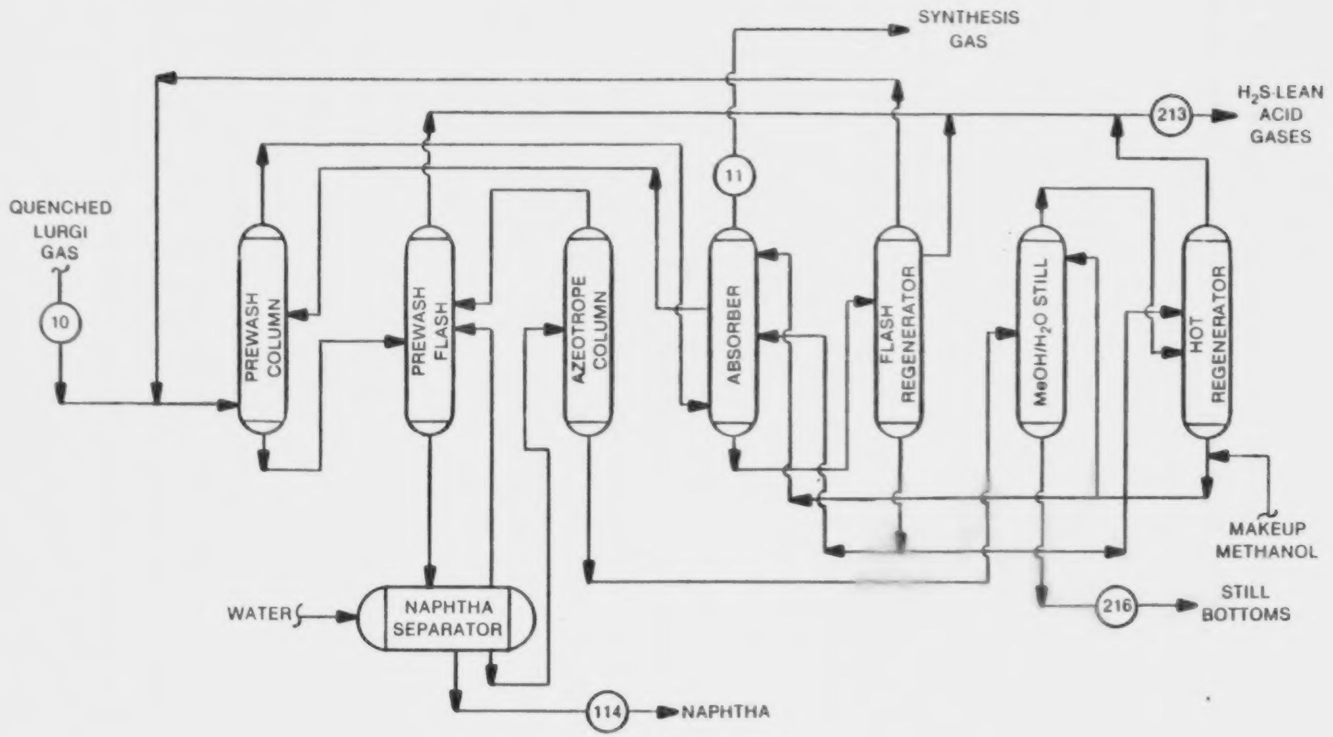


Figure 3-11. Nonselective Rectisol acid gas removal process

methanol is returned via cross-exchange to the top section of the main absorber, while the regenerator overhead gases are combined with the prewash and flash regenerator offgases (Stream 213).

Except for the use of a two-stage absorber and two separate flash columns, selective Rectisol (Figure 3-12) is similar to nonselective Rectisol. After leaving the prewash absorber, the raw gas is contacted with a CO_2-saturated methanol stream to remove H_2S in the first stage absorber. In the second stage absorber, pure methanol contacts the H_2S-free raw gas from the first stage absorber to remove CO_2. The resulting CO_2-rich methanol stream is then split into two streams, one of which is sent to the first stage absorber, while the second stream is sent to a flash and stripping unit. Here, the CO_2 is flashed to atmospheric pressure and then stripped with nitrogen or further regenerated by vacuum flashing, creating a CO_2-rich stream (Stream 214) which also contains small amounts of hydrocarbons and H_2. The H_2S-rich methanol stream from the first stage absorber is routed to a separate flash unit. Flash gases from this unit are combined with other sulfur-bearing offgases generated in the Rectisol unit. The liquid stream from the H_2S flash unit is then regenerated at elevated temperatures to remove the last traces of absorbed gases before being returned to the absorber.

The concentration of sulfur species in the H_2S-rich gas and in the CO_2-rich gas can be varied by modification of the Rectisol design in order to meet the given requirements. For a given set of product and pollution control specifications, Rectisol designs and costs will involve tradeoffs with other units within an integrated facility. Thus, it is difficult to define a generic "Rectisol" system without consideration of upstream and downstream processes and of constraints imposed by emission limitations and product specifications.

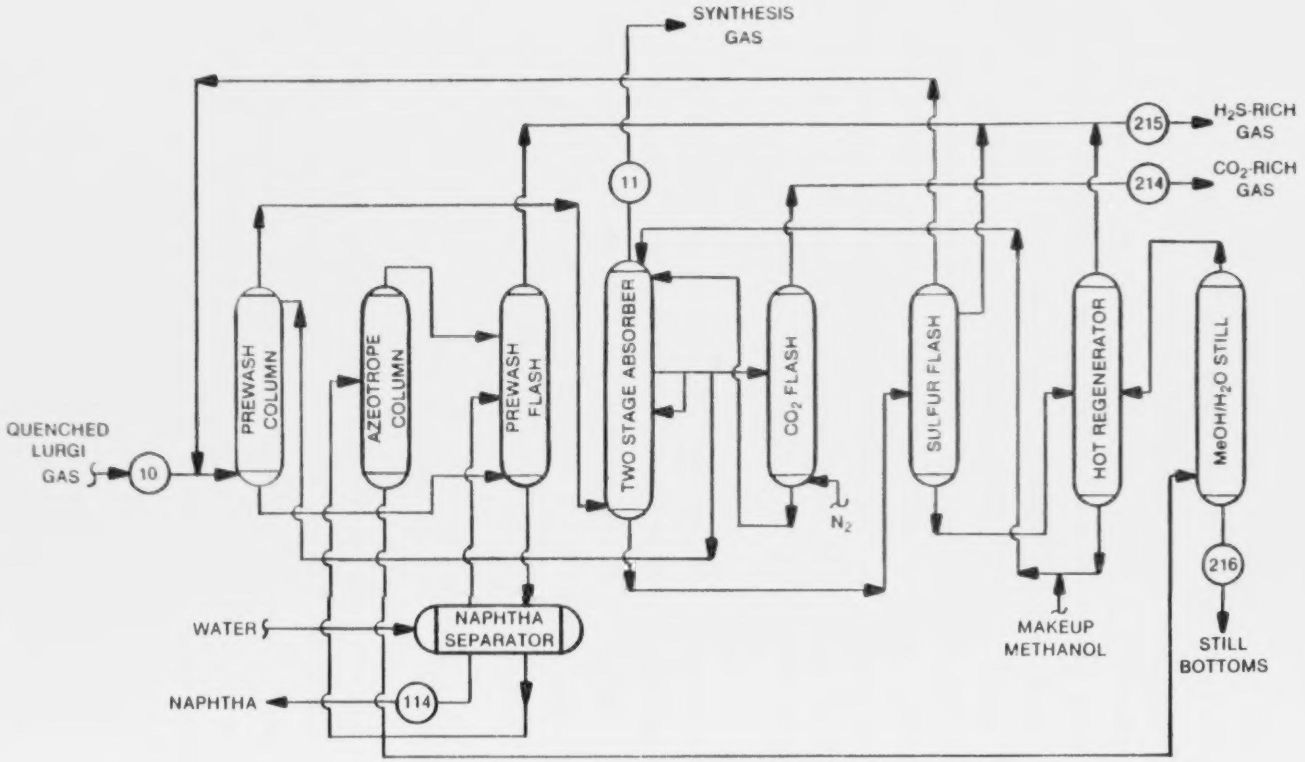


Figure 3-12. Selective Rectisol acid gas removal process

For purposes of this document, the material flows for selective Rectisol have been primarily based upon EPA test data for the Kosovo partially selective unit (3). In the Kosovo Rectisol unit, which was not designed with environmental constraints in mind, the fate of key species may differ from that in newer or more selective designs where environmental constraints have been placed upon the process designers. Controls for Rectisol acid gases that are evaluated and the associated costs in Section 4, to some extent, reflect the limitations of the Kosovo Rectisol design. Some of the control functions served by add-on units could be effected within Rectisol itself once the boundary conditions are known. Of course, certain incremental costs of Rectisol will be incurred with changes aimed ultimately at pollution control, but the costs of add-on processes would be reduced or eliminated.

Waste streams generated by the non-selective Rectisol design are H_2S-lean acid gas (Stream 213) and methanol/water still bottoms (Stream 216). For the selective Rectisol design, a CO_2-rich acid gas (Stream 214) and a H_2S-rich acid gas (Stream 215) are generated instead of an H_2S-lean acid gas. Section 3.3.5 discusses the expected characteristics of these waste streams.

3.3.4 Trace Sulfur Removal

The Rectisol process can routinely achieve sulfur levels down to 0.1 ppmv. However, a guard bed may be employed following the Rectisol unit as insurance to prevent catalyst poisoning during upset or transient conditions. Zinc oxide is the most commonly proposed guard bed material. Spent guard bed material is the only waste produced by trace sulfur removal.

3.3.5 Waste Streams From Gas Purification and Upgrading

Gas Liquor Depressurization Gases (Stream 209)

Some of the gases dissolved in gas liquor under pressure are released during gas liquor depressurization and tar and oil separation. The available data on this waste stream are presented in Table 3-13 (1,3). Both of these sources indicated that this stream was difficult to sample and quantify accurately. Thus, the composition data presented in Table 3-13 should be taken only as an indication of the types of constituents expected in gas liquor depressurization gases. Also, the temperature to which the gas liquor is cooled prior to depressurization will impact both the flow rate and composition of the waste stream. The flow rates of this waste stream are estimated to range from 90 to 190 kg-moles/hr for the base plants examined in this manual based on information in Reference 1.

Gas Liquor (Stream 210)

Table 3-14 presents data on the expected composition of Lurgi gas liquors after tar and oil separation but before filtration. After filtration, which is considered a part of bulk organics removal (see discussion in Section 4.2), Lurgi gas liquors are expected to contain essentially no suspended tars and reduced levels of suspended oils. The gas liquors contain large amounts of dissolved/suspended organics as reflected by high values for BOD_5, TOC, tar and oil, phenols, and organic acids. Inorganics present are mainly ammonia and bicarbonate, with smaller amounts of sulfide, sulfate, sulfite, thiocyanate, and cyanide. The gas liquors also contain some trace elements which were scrubbed from the raw Lurgi gas or leached from the dust removed from the raw gas.

TABLE 3-13. AVAILABLE DATA FOR GAS LIQUOR DEPRESSURIZATION GASES

Component	Westfield Data (dry basis)[a]	Kosovo Data (dry basis)[b]
Vol %		
H_2	3-10	9.8-11
O_2 + Ar	1-5	0.01-1.1
N_2	3-10	0.01-1.8
CO	3-8	1.0-7.2
CO_2	40-70	71-81
CH_4	2-6	3.4-6.1
C_2H_6		0.32-0.36
C_2H_4		<0.01-0.01
C_3's		0.21-0.45
C_4's		0.09-0.72
C_5's		<0.01-0.24
C_6^+'s		1.3-2.0
ppmv		
Benzene		9600-10,000
Toluene		1160-1250
Other Aromatics		135-200
H_2S	4-10[c]	2800-19,000
COS		87-150
CH_3SH		910-3400
C_2H_5SH		280-2300
NH_3	10-25[c]	420-20,000
HCN		64

[a] From Reference 1; only parameters shown were provided; moisture content not given.

[b] From Reference 3; moisture content given as 7.7 percent.

[c] Volume percent.

TABLE 3-14. ESTIMATED CHARACTERISTICS OF LURGI GAS LIQUORS

Constituent	Composition (in mg/L except pH)		
	Rosebud[a]	Illinois No. 6[a]	Dunn Co.[b]
TDS (non-volatile)	2,480	1,860	2,460
Sulfide (as H_2S)	55	290	49
Total S (as S)	225	360	144
Thiocyanate	6	160	85
Cyanide (as HCN)	5	37	46
Carbonate (as CO_2)	13,600	7,780	7,600
NH_3	7,610	4,800	2,900[c]
Monohydric Phenols	3,860[d]	1,940[d]	2,170[d]
Polyhydric Phenols	680[d]	340[d]	380[d]
Fatty Acids	2,000	380	230
Tar & Oil	150	500	300
TOC	7,640[d]	2,980[d]	4,190
BOD_5	10,600	4,570[d]	5,600[d]
COD	22,800	8,900	12,500
Cl	25	95	1
pH	8.2	7.8	8.9
Production Rate[e] (m^3/hr)	304	507	441

[a] Unless noted otherwise these are empirical data from Reference 1.

[b] Unless noted otherwise these are empirical data from References 9 and 25.

[c] Adjusted based on coal nitrogen content.

[d] Distributed based on information in References 9 and 25 to provide consistency between parameters indicated.

[e] Flow rates shown are for the liquids synthesis facilities examined. For SNG synthesis, shift conversion will consume some raw gas moisture and thus reduce the gas liquor flows by about 5 percent. However, most component concentrations would then be increased by about 5 percent.

Not all of the species/parameters listed in Table 3-14 have been reported for the subject coals. Unless otherwise indicated, the data represent actual measurements from testing of the subject coal(s). Where test data are not available, the values reported in Table 3-14 are extrapolated or adjusted from test data for other coals (9,25).

The quantity of gas liquor generated is determined mainly by the moisture content of the raw Lurgi gases, which in turn is a function of the coal moisture content and the steam/coal ratio to the gasifier. The flow rates shown in Table 3-14 assume no raw gas moisture is consumed by shift conversion (i.e., the flow rates are for the synthetic liquids facilities examined in this manual). For SNG production which requires shifting, the flow rates of gas liquor would be decreased by about 5 percent. However, the concentrations of most components presented in Table 3-14 would then be increased by about 5 percent.

The organics found in Lurgi gas liquors are a highly complex mixture and only a few specific compounds have been identified. Table 3-15 presents data on some specific organics in a gas liquor generated during gasification of a North Dakota lignite (25). As indicated, the calculated TOC and COD contributed by fatty acids, monohydric phenols, and aromatic amines together constitute about half of the TOC and COD measured in the gas liquor. Based on data from the Westfield Lurgi facility (26), polyhydric phenols may account for an additional 20 percent of the total organics. The remaining organics are thought (27) to be high molecular weight oxygenated compounds, many of which are not readily biodegradable (as suggested by the high COD/BOD_5 ratios in Table 3-14).

Table 3-16 presents recent data on the levels of certain polynuclear aromatic compounds found in gas liquors at the Kosovo plant (3). These data indicate that such compounds are present in gas liquor at levels of 1 mg/L or

TABLE 3-15. CONCENTRATIONS OF ORGANIC COMPOUNDS FOUND IN LURGI GAS LIQUOR (NORTH DAKOTA LIGNITE)

Compound	Concentration[a] (mg/L)	Calculated COD (mg/L)	Calculated TOC (mg/L)
Fatty Acids			
Acetic Acid	171	183	68.4
Propanoic Acid	26	39.3	12.7
Butanoic Acid	13	23.7	7.8
2-Methylpropanoic Acid	2	3.8	1.1
Pentanoic Acid	12	24.5	7.1
3-Methylbutanoic Acid	1	2.1	0.6
Hexanoic Acid	1	2.2	0.6
Total Fatty Acids	226	278.6	98.3
Monohydric Phenols			
Phenol	1,250	2,975	983
2-Methylphenol	340	857	265
3-Methylphenol	360	907	277
4-Methylphenol	290	731	226
2,4-Dimethylphenol	120	314	95
3,5-Dimethylphenol	50	131	39
Total Monohydric Phenols	2,410	5,915	1,866
Nitrogen Heterocycles and Aromatic Amines			
Pyridine	117	261	88.9
2-Methylpyridine	70	169	53.9
3-Methylpyridine	26	62.7	20.0
4-Methylpyridine	6	14.5	4.6
2,4-Dimethylpyridine	1	2.5	0.8
2,5-Dimethylpyridine	1	2.5	0.8
2,6-Dimethylpyridine	1	28.9	9.2
Aniline	12	28.9	9.2
Total Nitrogen Heterocycles and Aromatic Amines	234	544	179
Calculated Total[b]	2,870	6,738	2,143
Measured Total	NA	12,500	4,190
% Unidentified	NA	46	49

[a] From Reference 25.

[b] Calculated total values derived from summing the given concentrations.

NA = not applicable.

less. These data also show that the Phenosolvan process employed at the Kosovo plant largely removes these compounds as part of the phenol recovery step.

TABLE 3-16. CONCENTRATION OF POLYNUCLEAR AROMATIC COMPOUNDS IN RAW AND DEPHENOLIZED KOSOVO GAS LIQUORS (3)

Constituents	Concentration, mg/L Gas Liquor	 Dephenolized Gas Liquor[a]
Benz(a)anthracene	0.92	<0.008
7,12-dimethylbenz(a)anthrancene	0.23	<0.008
Benzo(a)fluoranthrene	0.68	<0.008
Benzo(a)pyrene (BAP)	0.19	<0.008
3-methylchloranthrene	<0.004	<0.008
Dibenz(a,h)anthracene	0.02	<0.008
252 Molecular Weight Group (as BAP)	1.3	0.29

[a] Phenosolvan process was used.

Shift Catalyst Regeneration/Decommissioning Offgases (Stream 211)

Based on information in Reference 7 for a Lurgi-based SNG facility, shift catalyst regeneration offgas is estimated to contain 1.1 volume percent SO_2 and about 92 percent water, with the remainder being N_2 and CO_2. Using the frequency of regeneration cited in Reference 7, maximum shift regeneration emissions are estimated to occur for approximately 60 hours per year and at a flow rate of 1800 kg-moles/hr. Thus, annual SO_2 emissions are calculated to be about 80 Mg. In addition to SO_2, some particulate matter, CO, and hydrocarbon emissions are also expected, but no data were available to estimate these.

For indirect liquefaction facilities, shift conversion may be required only to handle minor process upsets. Thus, for these facilities, the quantities of shift catalyst regeneration gases would be significantly lower than those estimated above for SNG synthesis facilities.

Spent Shift Catalyst (Stream 212)

The subject Lurgi synfuel facilities are calculated to have an inventory of about 120 Mg of shift catalyst (24). Assuming an average useful life of 3 years, about 40 Mg/year of spent catalyst would be generated. Table 3-17 presents data which indicate the range of concentrations of several elements expected to be present in spent shift catalyst. Co and Mo are the basic catalyst elements, and sulfur will always be present since Co-Mo-based catalysts are active only in the sulfided state. Coke or carbon accumulation is a primary cause of catalyst deactivation. Potentially volatile trace elements originally present in the feed coal (e.g., As, Pb, Se, and Hg) may also accumulate on the catalyst over time and contribute to loss of shift catalyst activity. No data are available on the quantities of these elements which might be found in spent shift catalyst.

TABLE 3-17. ESTIMATED COMPOSITION OF SPENT SHIFT CATALYST

Element	Concentration (wt% of catalyst material)	Comment
Co	5-15	Basic catalyst constituent[a]
Mo	15-25	Basic catalyst constituent[a]
S	5-20	Derived from coal. Catalyst is active in sulfided state.
C	5-10	Coke accumulation results in catalyst deactivation.

[a] Representative catalyst composition would be 20-50% $CoMoO_4$ on alumina (28).

H_2S-Rich Acid Gases (Stream 215)

This waste stream refers to the concentrated H_2S stream generated by the selective Rectisol design (Stream 215). Table 3-18 summarizes the expected compositions and flow rates of this stream for the cases in which the feed gas to the Rectisol unit has not undergone shifting. Similar compositions are expected for feed gas which has been shifted (SNG cases), with the exception of slightly higher CO_2 concentrations. Also, the total stream flow rate would be somewhat higher (10 to 15 percent) for shifted feed gas cases.

H_2S-rich acid gases from a Kosovo-type Rectisol unit are estimated to contain 4 to 10 percent sulfur species. However, much higher levels of sulfur species should be obtainable with Rectisol designs of high selectivity; H_2S levels of 25 percent or more are commonly obtained in selective Rectisol

TABLE 3-18. ESTIMATED COMPOSITIONS OF H_2S-CONTAINING ACID GASES FROM RECTISOL (LIQUIDS SYNTHESIS CASES)[a]

Component	H_2S-lean Acid Gases (Stream 213)			H_2S-rich Acid Gases (Stream 215)[b]		
	Subbituminous	Bituminous	Lignite	Subbituminous	Bituminous	Lignite
H_2	0.4	0.3	0.4	0.2	0.2	0.2
N_2 + Ar	0.1	0.1	0.1	0.2	0.3	0.2
CO	1.1	1.1	1.0	3.2	3.4	3.2
CO_2	94.5	92.7	93.9	86.4	82.1	86.9
CH_4	1.0	0.8	0.9	1.6	1.3	1.6
Aliphatics	1.1	1.8	2.1	3.0	2.7	3.1
Aromatics	0.01	0.01	0.01	0.01	0.01	0.01
H_2S	1.4	2.8	1.3	4.6	8.7	4.0
COS	0.02	0.03	0.02	0.05	0.09	0.05
CH_3SH	0.12	0.22	0.10	0.37	0.70	0.32
C_2H_5SH	0.03	0.05	0.02	0.08	0.16	0.07
HCN	0.01	<0.01	<0.01	0.03	0.01	0.01
NH_3	<0.01	<0.01	<0.01	0.01	<0.01	<0.01
Methanol	0.15	0.13	0.14	0.46	0.42	0.44
Total Flow, kg-moles/hr	6298	6317	5815	1774	2017	1863

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[a] All units, except Total Flow, are in mole percent. Data shown are for Rectisol feed gas which has not been shifted. If the feed gas has been shifted to obtain a proper SNG synthesis feed composition, the only significant differences would be somewhat higher levels of CO_2 and 10 to 15 percent increase in the stream flow rate.

[b] Compositions shown reflect partial H_2S enrichment.

See Appendix B for assumptions and bases used to estimate stream flows and compositions.

designs by Linde in oil gasification applications. H_2S-rich Lurgi acid gases are also estimated to contain some methanol and about 5 percent hydrocarbons (nonmethane hydrocarbons are around 3 percent). Data indicating the total methanol loss for selective Rectisol systems are available (29,30) although data relating to methanol losses in individual streams have not been published. Therefore, for evaluation purposes, the entire methanol loss has been assumed to be associated with the H_2S-rich acid gases, resulting in an estimated methanol concentration of about 0.45 percent.

The distribution of hydrocarbons indicated in Table 3-18 is based mainly on test data for the Kosovo plant (3). At that plant, the initial gases from flash regeneration of the H_2S-containing methanol are not segregated for recycle to the inlet gas stream or for use as plant fuel. And, the initial gases from flash regeneration of the CO_2-containing methanol are combined with the H_2S-rich acid gases. These initial flash gases will contain appreciable amounts of hydrogen, carbon monoxide, and low molecular weight hydrocarbons. Thus, lower concentrations of these components would be expected if the initial flash gases were segregated from the rest of the H_2S-containing regeneration offgases (Rectisol vendors report levels of 2 percent hydrocarbons can be obtained).

H_2S-Lean Acid Gases (Stream 213)

Sulfur containing waste gases from nonselective Rectisol are referred to as H_2S-lean acid gases (as compared to H_2S-rich acid gases from selective Rectisol). Table 3-18 summarizes the expected compositions of these gases. H_2S-lean acid gases contain 1 to 3 percent sulfur species and about 2 to 3 percent hydrocarbons (mostly methane and ethane). Unlike the case of selective Rectisol above where the organics can be significantly reduced in the H_2S fraction by design modifications, most of the C_3 to C_5 hydrocarbons originally present in raw Lurgi gas will report to the H_2S-lean acid gas in nonselective Rectisol designs. High-pressure flash gases containing absorbed CO, H_2, and low molecular weight hydrocarbons (mainly methane) are recompressed for recycle in nonselective designs, but this step is already reflected in the data in Table 3-18.

CO_2-Rich Acid Gases (Stream 214)

The selective Rectisol design generates a CO_2-rich stream containing greater than 95 percent CO_2. Table 3-19 summarizes the estimated compositions and flow rates of this waste stream. As indicated, CO_2-rich acid gases contain less than about 20 ppmv H_2S and about 80 ppmv COS with essentially no mercaptans. If necessary selective Rectisol units can achieve levels of less than 10 ppmv of total sulfur species in the CO_2-rich acid gas stream. Nonmethane hydrocarbons (mostly ethane) amount to about 2 percent of the waste stream while aromatics are present only at the low (less than 10) ppmv level. About two-thirds or more of the CO_2 in the Rectisol feed gas ultimately is present in the CO_2-rich acid gas stream. Not indicated in Table 3-19 is nitrogen, which is used for stripping in most selective Rectisol units. This nitrogen adds about 20 percent to the volume of the CO_2-rich acid gases.

Methanol vapor will also be present in the CO_2-rich acid gases, although no data are publicly available at present to indicate the exact level of this compound. For analysis purposes all methanol losses from the selective Rectisol process are assumed to be associated with the H_2S-rich acid gases. Some portion of this methanol will in actuality be contained in the CO_2-rich acid gas and synthesis gases.

TABLE 3-19. ESTIMATED COMPOSITIONS OF CO_2-RICH OFFGAS (Stream 214) FROM SELECTIVE RECTISOL[a]

Component	Liquids Synthesis Cases[b]			SNG Synthesis Cases[b]		
	Subbituminous	Bituminous	Lignite	Subbituminous	Bituminous	Lignite
H_2, %	1.1	0.9	0.9	1.0	0.9	0.9
N_2 + Ar, %	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
CO, %	0.1	0.1	0.1	0.1	0.1	0.1
CO_2, %	96.0	96.7	96.1	96.6	97.0	96.5
CH_4, %	0.4	0.3	0.4	0.4	0.3	0.3
Aliphatics, %	2.3	2.0	2.5	2.0	1.8	2.2
Aromatics, ppmv	4	3	3	3	4	4
H_2S, ppmv	8	16	7	7	14	7
COS, ppmv	36	69	25	21	29	18
HCN, ppmv	10	9	10	10	10	10
NH_3, ppmv	5	5	5	5	5	5
Total Flow, kg-moles/hr	3568	4341	4001	4204	4897	4571

[a] Compositions shown exclude stripping nitrogen. If included, the total flow would be increased by about 20 percent.

[b] The difference between liquids synthesis and SNG synthesis cases is that the feed gas to the Rectisol unit has undergone shift conversion for the SNG cases, but not for the liquids cases. See Appendix B for assumptions and bases used to estimate stream flows and compositions.

Methanol/Water Still Bottoms (Stream 216)

Water contained in the feed gas to the Rectisol unit and process water added to enhance recovery of byproduct naphtha are recovered from the methanol/water still as a waste stream. The amount of water added for naphtha recovery was assumed to be five times the weight of naphtha recovered based on design information from Reference 10. The still bottoms waste stream is estimated to contain minor quantities (less than 100 mg/L) of dissolved ammonia, cyanides, methanol, and other organics, plus all of the HCl present in the Rectisol feed gas. Table 3-20 summarizes the estimated composition and flow rates of this stream.

TABLE 3-20. ESTIMATED COMPOSITION OF METHANOL/WATER STILL BOTTOMS[a] (Stream 216)

Component	Concentration, mg/L
HCN	15-20
NH_3	60-75
Methanol	45-60
Other Organics	30-40
HCl	600-700

Estimated compositions based on data in Reference 4.
[a]Estimated flow rates are: Rosebud coal-9.9 m^3/hr; Illinois No. 6 coal-12 m^3/hr; and Dunn County lignite-9.9 m^3/hr.

Spent Sulfur Guard Material (Stream 217)

Most proposed designs of Lurgi-based synthetic fuels facilities do not indicate use of sulfur guards behind the Rectisol unit. This is a reflection of the high degree of removal of sulfur species achievable by the Rectisol unit. As a result of this high degree of sulfur removal, it is difficult to estimate the generation rate of spent sulfur guard material. In many cases a sulfur guard may not even be used.

3.4 PRODUCT SYNTHESIS

Four synthesis operations are examined in this manual for converting sulfur-free Lurgi synthesis gases into synthetic fuels. Included are production of substitute natural gas (SNG) via methanation and three liquid fuels synthesis processes: methanol, Mobil M-gasoline, and Fischer-Tropsch. Information on SNG synthesis is presented in Section 3.4.1, while information on the liquids synthesis processes is presented in Section 3.4.2. Section 3.4.3 presents information on the characteristics of the waste streams generated by the synthesis operations.

3.4.1 Synthesis of Substitute Natural Gas

Methanation of Lurgi synthesis gases (Stream 12) involves the catalytic reaction of the hydrogen and carbon oxides in the synthesis gas to produce methane.

$$3H_2 + CO \rightarrow CH_4 + H_2O + \text{heat}$$
$$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O + \text{heat}$$

The resulting product gases have, after dehydration, a composition and higher heating value comparable to that of natural gas.

The methanation reactions are carried out in steel pressure vessels at temperatures between 640 K and 760 K. Reactor feed stream requirements include a maximum concentration of four percent CO (to minimize the temperature rise across the reactor), a moisture level below saturation at 330 K, and the essential absence of sulfur and chlorine compounds. Normally a methanation unit consists of two reactors in series with the second stage used for final methanation as shown in Figure 3-13. Additional equipment includes heat exchangers, a knockout drum to condense and remove moisture, and a product

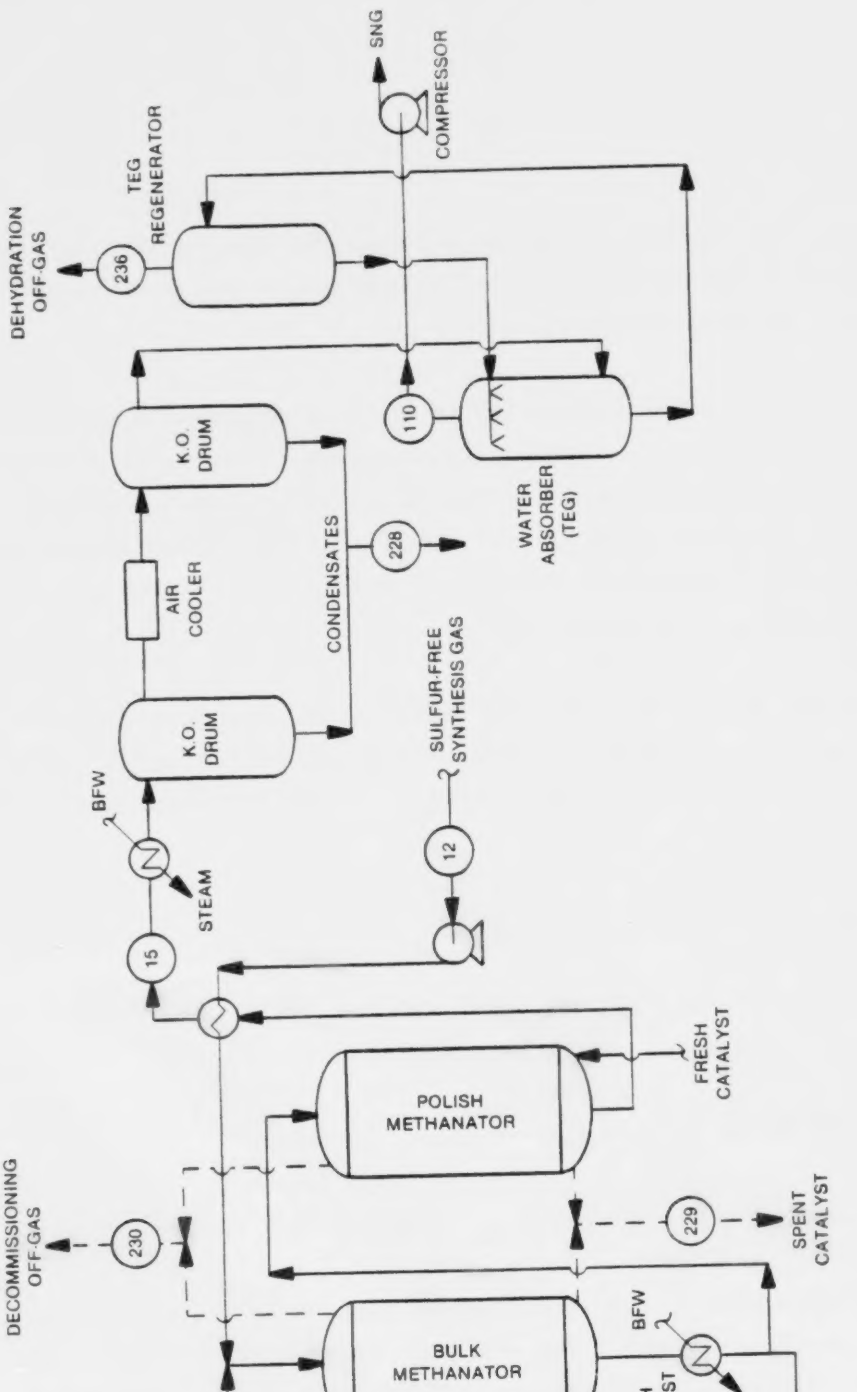

Figure 3-13. Methanation and dehydration for SNG synthesis

recycle system. The recycle system helps to control the reactor exit temperature and permits dilution of the synthesis feed gas to obtain a reactor feed gas containing less than four percent CO.

Dehydration and compression of SNG is required following methanation if the SNG (Stream 110) is to be transported over long distances or introduced into the U.S. natural gas transportation (pipeline) system. A variety of processes can be used for dehydration. The triethylene glycol dehydration process is shown in Figure 3-13. Table 3-21 presents calculated material flows for the SNG synthesis operation.

Waste streams generated by the synthesis of SNG include condensates from the methanation unit (Stream 228), spent methanation catalysts (Stream 229), methanation catalyst decommissioning offgases (Stream 230), and dehydration offgases (Stream 236).

3.4.2 Synthesis of Synthetic Liquid Fuels

Methanol synthesis and hydrocarbon production via Fischer-Tropsch (F-T) synthesis can be represented by the following reactions:

$$CO + 2H_2 \xrightarrow{\text{CATALYST}} CH_3OH + \text{heat (Methanol Synthesis)}$$

$$nCO + (2n + .5x)H_2 \xrightarrow{\text{CATALYST}} C_nH_{2n+x} + nH_2O + \text{heat (F-T Synthesis)}$$

where n ranges from 1 to 20 and is determined by process operating conditions, and x = 2 for parafins and x = 0 for olefins. Since Lurgi synthesis feed gases (Stream 12) would usually contain some CO_2 in addition to CO and H_2 and since synthesis catalysts are also active for the interconnecting water gas shift reaction ($CO + H_2O \rightarrow CO_2 + H_2$), the hydrogenation of CO_2 may be represented as follows:

TABLE 3-21. ESTIMATED MATERIAL FLOWS FOR SNG SYNTHESIS - ROSEBUD COAL

Stream No.	12	228	236	110
Stream Name	Sulfur-Free Synthesis Gas	Methanation Condensate[a]	Dehydration Offgases	Product SNG
kg-moles/hr				
H_2	8255			123.7
O_2	39			
N_2+Ar	158			158
CO	2103			2.1
CO_2	448	0.1		23.1
CH_4	2017	0.4		4633.6
C_2^+	46			
Total Dry Gas	13,066			4940.5
kg/hr				
H_2O		54,300	204	10
Total, kg/hr	135,664	54,332	204	81,128

[a] Based on data from Reference 10.

Blanks indicate not applicable or no data available.

Number of significant figures overstates the accuracy of the calculated estimates.

$$CO_2 + 3H_2 \xrightarrow{\text{CATALYST}} CH_3OH + H_2O + \text{heat (Methanol Synthesis)}$$

$$nCO_2 + (3n + .5x)H_2 \xrightarrow{\text{CATALYST}} C_nH_{2n+x} + 2nH_2O + \text{heat (F-T Synthesis)}$$

Although the theoretical stoichiometry for synthetic liquids production calls for a ratio of 2 moles of H_2 per mole of CO and 3 moles of H_2 per mole of CO_2, in practice the following ratio is required (5):

$$H_2/(2CO + 3CO_2) = 1.03$$

The major difference in methanol and F-T synthesis is in the catalysts used and temperatures and pressures employed. Methanol synthesis is accomplished over Cu/Zn-based catalysts at 470 K and 3.5 to 7.0 MPa while F-T synthesis proceeds at pressures up to 2.5 MPa over iron oxide-based catalysts at 590 to 600 K (fluidized bed) and 490 to 530 K (fixed bed) (31).

Mobil M-gasoline synthesis from methanol can be represented as follows:

$$nCH_3OH \xrightarrow{\text{CATALYST}} (CH_2)_n + nH_2O$$

The process employs a zeolite-based catalyst and operates at about 570 to 680 K and 2.1 MPa (5).

For methanol, F-T, and Mobil M-Gasoline synthesis processes, high conversions of synthesis gas are achieved only when gas recycle is employed due to performance limitations of the catalysts. Complete recycle, however, is not possible due to the buildup of inert components in the system (e.g., N_2, Ar, CH_4). Thus, all synthesis processes produce a purge gas containing inerts as well as CO and H_2. Variations in process designs for synthesis reactors reflect different approaches to heat recovery, maximum synthesis gas conversion, minimum recycle, and minimum purge. The discussions below provide some detail about the subject synthesis processes.

Methanol Synthesis

Methanol production is a fully commercialized technology with a number of firms offering conversion processes - Lurgi, ICI, Chem Systems, Vulcan-Cincinnati, Mitsubishi, Nissui-Topsoe, and Selas-Polimex (31). As an example, Figure 3-14 is a simplified flow diagram of the ICI process. In the ICI process, compressed synthesis feed (Stream 12) is mixed with recycle gas and heated by exchange with methanol product before entering the synthesis reactor. The bulk of the reactor feed enters the top of the reactor while a portion of the gas, which has bypassed remaining heat exchangers, is injected at various levels in the reactor. The cooler "quench" gases serve as the main temperature control in the system. Crude methanol vapors which exit the bottom of the reactor are cooled by feed/product heat exchange and expansion in a turbo-expander before the crude methanol product (Stream 107) is condensed. Condenser overhead is partially recycled, with a purge stream withdrawn from the system through an expansion turbine. Depressurization gases from crude methanol pressure letdown are combined with these purge gases.

In the Lurgi methanol production process, a commercial alternative to the ICI process, the fixed bed reactor would be replaced by a boiling water jacketed tube reactor with catalyst in the tubes (5). In the Lurgi case, isothermal reactor operation is realized and no gas quench is necessary. In all methanol synthesis processes, large amounts of heat are recovered as medium pressure steam.

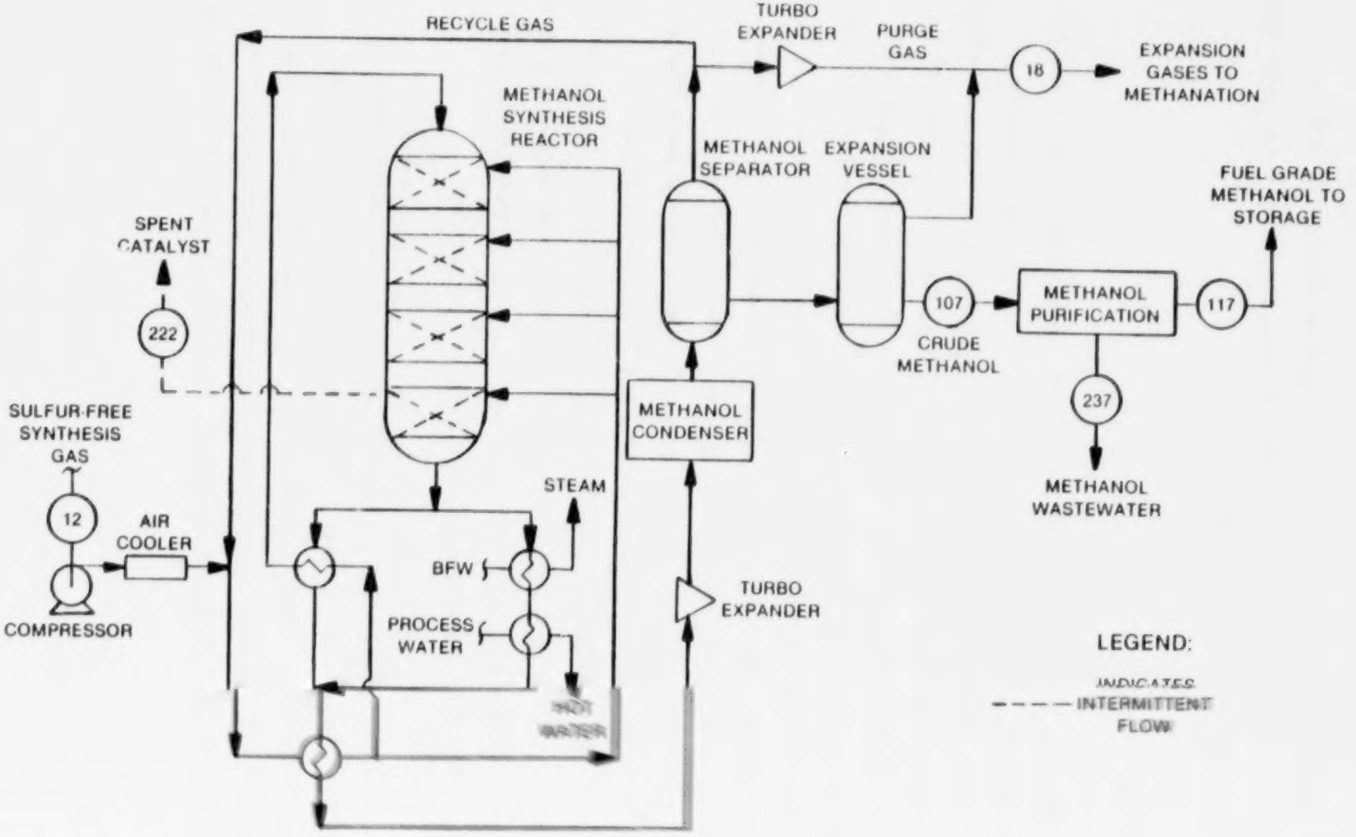

Figure 3-14. ICI methanol synthesis process

Regardless of the specific process employed, all methanol synthesis processes generate a continuous purge gas stream (Stream 18) and, on an intermittent basis, spent catalyst (Stream 222). The purge gas (plus depressurization gases) are useful as sulfur-free fuel gases or feed gases for production of coproduct SNG (Stream 110). If the crude methanol product is distilled to produce a fuel grade methanol product (Stream 117) an aqueous waste stream (Stream 237) is generated.

Table 3-22 presents a calculated material balance for methanol synthesis. As indicated in this table, a large amount of purge gas is produced due to the high methane content of the Lurgi synthesis feed gas. These purge gases are subsequently methanated to produce a SNG coproduct as discussed later in this section.

Mobil M-Gasoline Synthesis

The Mobil M-Gasoline process is depicted in Figure 3-15 (32). Crude methanol (Stream 107) is vaporized by heat exchange with the reactor product and fed to the dimethyl ether (DME) reactor where it is catalytically converted to an equilibrium mixture of methanol, dimethyl ether, and water vapor. DME reactor product is subsequently converted to hydrocarbons in Mobil M-Gasoline reactors, with temperature control obtained by recycling cooled gas from product separation. The DME reactor inlet conditions are about 570 K and 2.3 MPa while M-Gasoline reactor inlet temperature is about 600 K. Product vapors from the M-Gasoline reactors are cooled by methanol feed heat exchange, by generation of steam in a waste heat boiler, and by air cooling. Crude liquid product is separated in a knockout drum. Drum overhead is split into a recycle stream and a purge stream. The bulk of the liquid product is sent to the product fractionation unit, with a small slipstream injected at the inlet

TABLE 3-22. ESTIMATED MATERIAL FLOWS FOR METHANOL SYNTHESIS - ROSEBUD COAL[a]

Stream No.	12	117	207	[illegible]	228	231	236	[illegible]
Stream Name	Feed Gas	Fuel Grade Methanol	Methanol Wastewater	Purge Gas To Methanation	Methanation Condensate[b]	CO_2 Removal Offgas	Dehydration Offgas	Co-Product SNG
kg-moles/hr								
H_2	7596	0.04		2608		0.1		80
N_2, Ar, O_2	197	0.01		198		0.1		1598
CO	2749	0.03		1980		0.001		0.095
CO_2	606	3.7		360	0.05	70		3
CH_4	2017	1.1		2636	0.2	2.4		25531
C_2^+	46	0.25		48				
CH_3OH		2797	1.6	42				
ROH+HCs		2.5	0.37	0.89				
Total dry gas	13,211			4870		72		27683
kg/hr								
H_2O		88	5282	30	20,180	78	329	6
Total, kg/hr	158,451	90,080	5289	62,600	20,180	3180	329	46,200

[a] Based on data from Reference 5 unless otherwise noted.

[b] Based on data from Reference 10.

Blanks indicate not applicable or no data available.

Number of significant figures shown overestimates the accuracy of the calculated estimates.

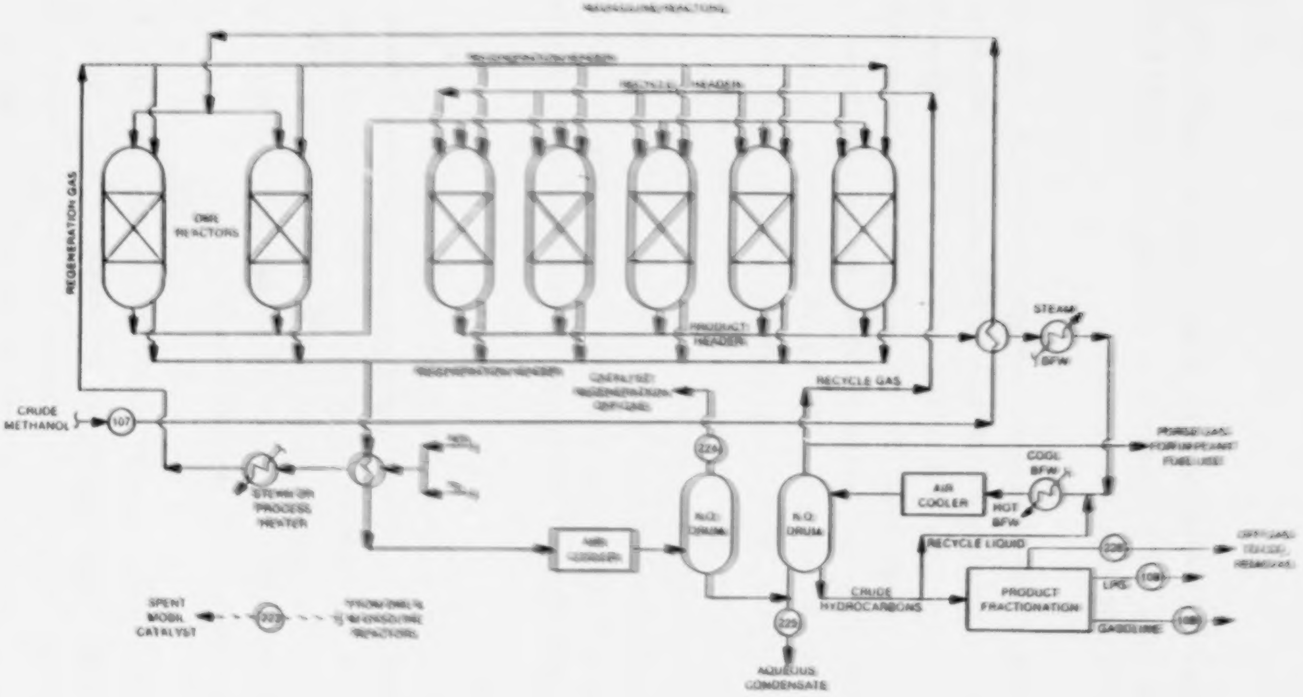

Figure 3-15. Mobile M-gasoline synthesis and product recovery (32)

to the boiler feed water heat exchanger to control durene crystallization. The aqueous condensate from the knockout drum (Stream 225) constitutes the only continuous waste stream from the process.

Both the DME catalyst and M-Gasoline catalyst require periodic regeneration. The DME catalyst accumulates coke slowly and requires regeneration perhaps once or twice per year. The M-Gasoline catalyst requires regeneration about every two weeks to remove coke (5). Regeneration is accomplished using N_2 to purge hydrocarbons from the system followed by air injection. Control of inlet O_2 level and injection of cooled recycle gas to the system maintain combustion temperatures below 760 K. Regeneration offgas is cooled by exchange with fresh regeneration gas and by air cooling. Any water of combustion is condensed in a knockout drum before depressurization and venting to the atmosphere. As depicted in Figure 3-15, five M-Gasoline reactors constitute a "train" with one reactor being regenerated while four are in service. Thus, regeneration is more-or-less continuous, resulting in the routine generation of an offgas.

Table 3-23 presents calculated material flows for Mobile M-Gasoline synthesis. A large methanol synthesis purge stream is produced which accounts for over half of the total product heating value. This stream, along with the fractionation offgas is subsequently converted to coproduct SNG (Stream 110). Most of the remaining fuel value is recovered as gasoline (Stream 108), with lesser amounts of LPG (Stream 109) also produced.

The methanol conversion condensate waste (Stream 225) contains the oxygenated organics (ketones, acids) which are generated in small amounts in the Mobil M-Gasoline reactors. Other waste streams generated by Mobil M-Gasoline synthesis include Mobil M catalyst regeneration offgases (Stream 224) and spent catalysts (Stream 223).

TABLE 3-23. ESTIMATED MATERIAL FLOWS FOR MOBIL M-GASOLINE SYNTHESIS - ROSEBUD COAL[a,b]

Stream No.	12	18	107	225	226	228	231	236	110
Stream Name	Feed Gas to Methanol Synthesis	Purge and Expansion Gases to Methanation	Crude Methanol	Mobil Synthesis Wastewater	Fractionation Offgases to CO_2 Removal	Methanation Condensate[c]	CO_2 Removal Offgas	Dehydration Offgas	SNG Co-product
kg-moles/hr									
H_2	7596	1608	0.05		0.7		0.1		81
N_2,Ar,O_2	197	158	0.02		0.01		0.1		158
CO	2749	190	0.03	0.02	0.3		0.001		1.3
CO_2	606	310	6.7	1.2	6.3	0.05	76		3
CH_4	2017	2016	1.3		19	0.2	2.6		2539
C_2S	46	45	0.3		5.8		0.005		5.8
CH_3OH		42	2799						
ROH+HCs		0.89	3.1						
C_2s					2.1				2.1
C_3^+s				0.6	2.4				2.4
Organic acids				4.8					
Ketones				3.6					
Total dry gas	13,211	4370			36		79		2793
kg/hr									
H_2O		10	5298	55,450	35	20,180	85	332	4
Total, kg/hr	158,451	61,680	95,430	55,990	1022	20,180	3460	332	45,820

[a] Main products from Mobil M-Gasoline Synthesis are: Blended Gasoline (108) - 32,510 kg/hr; C_3 LPG (109) - 1756 kg/hr; C_4 LPG (109) - 2972 kg/hr

[b] Based on data from Reference 5 unless otherwise noted.

[c] Based on data from Reference 10.

Blanks indicate not applicable or no data available.

Number of significant figures shown overestimates the accuracy of the calculated estimates.

Fischer-Tropsch (F-T) Synthesis

The F-T process can produce a wide range of products from methane to heavy fuel oil. Generally, fluidized bed designs operating at higher temperatures produce a lighter mix of products than fixed bed designs. For the purpose of analysis, it was assumed that the fluidized bed design similar to that used at Sasol, S.A. (called the Synthol process) would be utilized in the U.S. since major emphasis in synfuels production would be on light motor fuels. However, even the Synthol process produces a range of products from middle distillates to methane. A Lurgi-based F-T synthesis facility could be designed to produce mostly liquid products by: 1) steam reforming of methane and other light hydrocarbons for recycle and/or 2) catalytic cracking of heavier oils. Such an approach, however, would result in low overall thermal efficiencies due to extensive heat losses. Thus, a mix of hydrocarbon products including SNG, LPG, gasoline, diesel fuel, and alcohols is viewed as a more practical scenario for U.S. facilties and is the route used for analysis purposes in this manual.

Figure 3-16 is a flow diagram of the Synthol process (5). Purified synthesis gas (Stream 12) and recycle gas are compressed together and heat exchanged against hot reactor product. Synthesis gas is mixed with circulating iron catalyst in the Synthol reactor where the synthesis reactions proceed. Reaction heat is removed by hot oil circulating in tubes internal to the reactor. Catalyst and vapor products are separated in a cyclone system and catalyst solids are recycled. Crude product vapors are cooled in a hot wash tower which uses cooled F-T recycle oil as the wash medium. Heat is recovered via feed/product exchange and by generation of steam in waste heat boilers.

Heavy oil condensate is sent to product fractionation while hot wash tower overhead is sent to a cold wash tower for recovery of lighter oils.

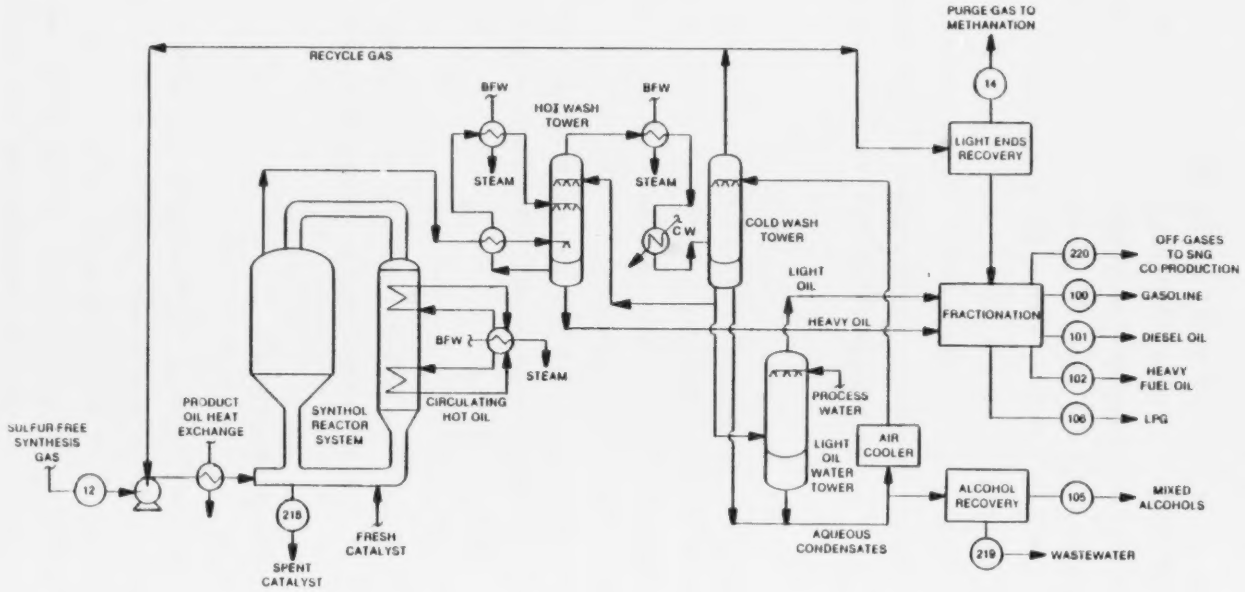

Figure 3-16. Fischer-Tropsch (Synthol) synthesis and product recovery (5)

In the cold wash tower, cool process water spray effects condensation of most of the light hydrocarbons. Oxygenated organics (alcohols, ketones, acids) become dissolved in the aqueous condensate. Liquid light oil is further washed with process water and sent to product fractionation. The aqueous condensate is sent to alcohol recovery where the wastewater is steam stripped and hydrogenated to recover a mixed alcohol product (Stream 105). Stripper bottoms (Stream 219), containing mostly organic acids, constitute the aqueous waste from the F-T process. Overhead vapors from the cold wash tower are split into a recycle and a purge stream, with the latter sent to light ends recovery.

Table 3-24 presents calculated material flows for F-T synthesis. Over half of the heating value of F-T products is accounted for by the purge gas (Stream 14) and fractionation unit offgas (Stream 220) which are subsequently converted to SNG (Stream 110). F-T products are about 80 percent gasoline range hydrocarbons (Stream 100) and 20 percent diesel/fuel oil hydrocarbons (Streams 101 and 102). Alcohols (Stream 105) represent significant chemical byproduct(s).

Wastewater generated in the alcohol recovery unit (Stream 219) and spent F-T catalyst (Stream 218) are the major wastes from F-T synthesis.

Crude Synthetic Liquid Fuels Upgrading

The crude liquid fuel products of methanol, F-T, and Mobil M-Gasoline synthesis processes will require upgrading (probably on site) to yield final products which are marketable as substitutes for petroleum-derived products. This is particularly true for motor gasolines, where crude coal-derived gasoline fractions would not meet octane requirements for the retail market in the U.S. F-T and Mobil M-Gasoline products could be upgraded by HF alkylation of the C_3-C_4 fraction to yield gasoline-blend hydrocarbons and commercial

TABLE 3-24. ESTIMATED MATERIAL FLOWS FOR FISCHER-TROPSCH SYNTHESIS - ROSEBUD COAL[a,b]

Stream No.	12	14	219	220	228	238	231	236	110
Stream Name	Feed Gas to F-T Synthesis	Purge Gases to Methanation	Wastewater From Alcohol Recovery	Fractionation Offgases to CO_2 Removal	Methanation Condensate[c]	Wastewater From CO_2	CO_2 Removal Offgas	Dehydration Offgas	Co-Product SNG
kg-moles/hr									
H_2	7596	1363		8.2			0.3		89
N_2, Ar, O_2	197	155		2.6			0.4		157
CO	2749	84		1.6			0.01		2
CO_2	606	310		160	0.04		219		14
CH_4	2017	2129		161	0.14		7.8		2766
C_2s	46	83		99			0.2		99
C_3s				33			0.1		33
C_4^+s		0.8		0.2					0.2
Organic Acids			13.6						
Total dry gas	13,211	4126		466			228		3160
kg/hr									
H_2O			75,900	332	18,300	358	247	375	5
Total, kg/hr	158,451	59,760	76,720	14,390	18,300	358	10,040	375	53,930

[a] Main products from Fischer-Tropsch Synthesis are:
Blended Gasoline (100) - 19,660 kg/hr
C_3 LPG (106) - 1284 kg/hr
C_4 LPG (106) - 195 kg/hr
Diesel Oil (101) - 3986 kg/hr
Heavy Fuel Oil (102) - 1167 kg/hr
Mixed Alcohols (105) - 3380 kg/hr

[b] Based on data from Reference 5 unless otherwise noted.

[c] Based on data from Reference 10.

Blanks indicate not applicable or no data available.

Number of significant figures shown overstates the accuracy of the calculated estimates.

grade LPG, by naphtha hydrotreating (in the F-T case) for destruction of olefins and oxygenated organics, by catalytic reforming of naphtha to produce more cyclic and branched chain hydrocarbons, by C_5/C_6 isomerization to increase the anti-knock quality of pentanes and hexanes, and by catalytic polymerization to convert propene/butene fractions into higher molecular weight gasoline blending compounds. All of the upgrading facilities are expected to be able to use currently available petroleum refinery technology. Of course, the specific characteristics of the crude synthetic liquids must be considered in the design of the upgrading facilities.

Since the feed streams to the upgrading processes in an indirect liquefaction plant are not expected to have any unusual characteristics relative to current refinery experience, waste streams generated during these upgrading operations are not expected to present any unique treatment problems. For these reasons, and due to the multiplicity of possible options for product upgrading, waste stream characteristics and pollution control alternatives for product upgrading processes are not specifically discussed in this PCTM.

SNG Coproduction

All of the synthetic liquid fuels synthesis processes generate a purge gas containing large amounts of methane and unreacted CO_x and H_2. Several options are available to handle the purge gas including use as an onsite fuel, reforming to generate additional synthesis gas, or conversion of the residual hydrogen and carbon oxides into methane to produce SNG. Because Lurgi-derived synthesis gases initially contain large amounts of methane and because SNG has considerable market value, the methanation option was selected for analysis purposes in this PCTM. In actual practice the decision regarding the disposition of synthesis purge gases involves site- and design-specific considerations which are outside the scope of this manual. The methanation reactions are the same as those discussed earlier in Section 3.4.1 on Synthesis of

SNG. Following methanation, residual CO_2 and moisture are removed and the co-product SNG is compressed to pipeline pressure for distribution. Any of a number of processes can be used for CO_2 and H_2O removal. The MEA and triethylene glycol processes are shown in Figure 3-17.

Waste streams produced by the coproduction of SNG include methanation (Stream 228) and CO_2 removal (Stream 238) condensates, CO_2 containing offgases (Stream 231), dehydration offgases (Stream 236), methanation catalyst decommissioning offgases (Stream 230), and spent methanation catalyst (Stream 229).

3.4.3 Waste Streams Generated by Synthesis Operations

The product synthesis and upgrading operations do not routinely generate any unique gaseous waste streams. Nonunique waste streams generated include flue gas from process heaters, CO_2 removal offgas from the coproduction of SNG, and SNG dehydration offgas. However, periodic regeneration or decommissioning of synthesis catalysts results in the generation of offgases. In addition, spent catalysts represent solid wastes. Aqueous wastes are routinely generated by methanol, F-T, Mobil M-Gasoline, and SNG synthesis. In the methanol, F-T, and Mobil cases, these wastewaters contain alcohols and oxygenated organics. In the SNG case, condensates contain only dissolved gases and are considered clean and reusable.

Spent Methanol Synthesis Catalyst (Stream 222)

No data are currently available in the public domain relating to the characteristics or quantity of spent methanol catalyst. For the subject facility a catalyst inventory of 150 Mg having a useful life of 3 to 5 years is assumed. Therefore, based on these assumptions, the maximum annual spent catalyst rate is 50 Mg.

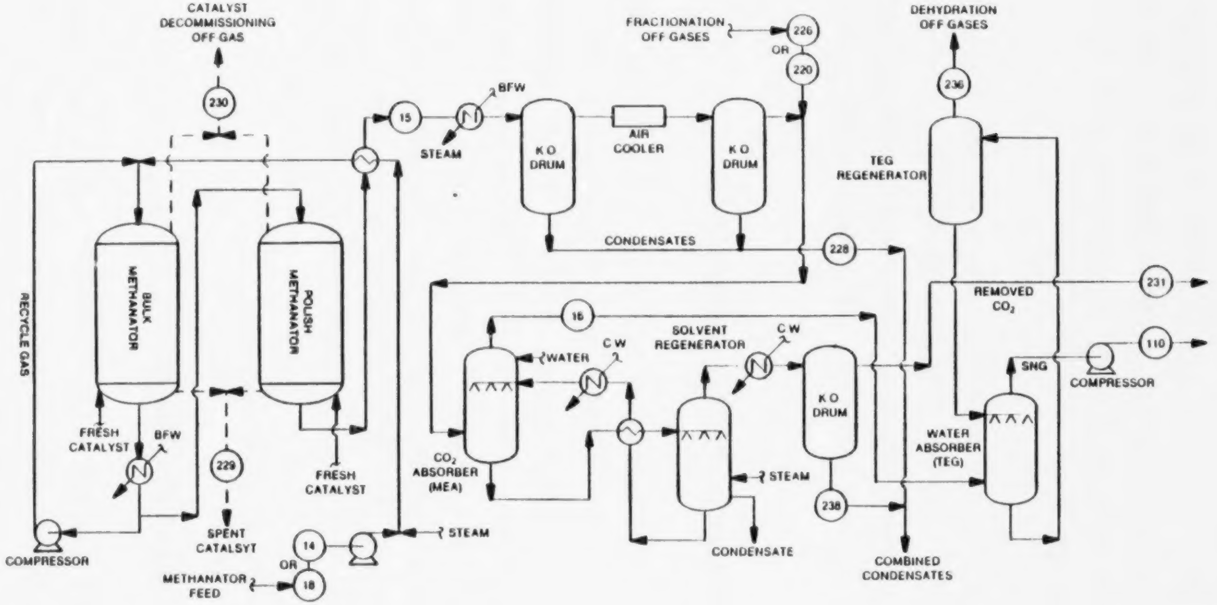

Figure 3-17. Methanation, CO_2 removal, and drying for co-production of SNG with synthetic liquid fuels

Spent F-T Catalyst (Stream 218)

As with methanol catalyst, no data are currently available on the properties of spent F-T catalyst. In addition, the metal compositions other than iron which are used in formulations of fresh catalysts are proprietary. For the subject facilities, it is estimated that there will be about 3500 Mg/yr of spent F-T catalyst (5).

Spent Mobil Catalysts (Stream 223)

Mobil catalysts are zeolite-based (synthetic clay-like) materials. No data are publicly available at present on the characteristics of these catalysts. Most zeolites are essentially inert in aqueous environments. However, it is possible that trace metals such as Zn, Co, Cu, and Cr may be leached from the waste. It is estimated that the subject facilities would generate about 40 Mg year of spent DME catalyst and about 150 Mg/year of spent M-Gasoline catalyst (5).

Mobil Synthesis Catalyst Regeneration Offgas (Stream 224)

Based on design data contained in a Mobil report (5) concerning the number of catalyst vessels, regeneration frequency, regeneration duration, and offgas volume, it is anticipated that catalyst regeneration will occur over a period of about 3800 hours per year with an average flow rate of approximately 100 kg-moles/hr. Pollutants expected in this offgas stream include CO at approximately 1 percent by volume, organics (from purging), and perhaps particulates.

Spent Methanation Catalyst (Stream 229)

Nickel-based methanation catalysts are eventually deactivated by physical degradation of crystal size and by chemical accumulation of poisons such as sulfur. The quantity of spent catalyst is estimated to average about 20 Mg/year.

Methanation Catalyst Decommissioning Offgas (Stream 230)

Methanation catalyst contains nickel in reduced form and is thus pyrophoric in nature. Prior to removal of spent catalyst from the bed, the material is oxidized with air in a controlled manner to convert nickel to its oxide. No information is available on the characteristics of the catalyst decommissioning offgas. However, the possibility exists that nickel compounds, such as $Ni(CO)_4$, could be produced during decommissioning.

F-T, Mobil M, and Methanol Synthesis Wastewaters

Wastewaters or condensates generated by these synthesis operations will contain varying levels of dissolved organics (mainly water soluble organics such as acids, ketones, alcohols, etc.). However, they will contain no to very low levels of dissolved inorganics, trace elements, or sulfur or nitrogen species due to the absence (or near absence) of inorganics, sulfur, and nitrogen species in the synthesis feed gas.

Condensates generated by the alcohol recovery step in Fischer-Tropsch synthesis (Stream 219) are estimated to have the following gross characteristics (5):

Production rate	72-77 m^3/hr
Organic acids	11,000-13,000 mg/L
COD	11,000-13,000 mg/L
BOD_5	8,000-9,000 mg/L
TOC	4,300-4,800 mg/L

Condensates generated by the Mobil product separation step (Stream 225) are estimated to have the following gross characteristics (5,24):

Production rate	56-59 m^3/hr
Organic acids	3,800-4,100 mg/L
Ketones	3,800-4,100 mg/L
C_6+ hydrocarbons	1,100-1,200 mg/L
COD	16,000-18,000 mg/L
BOD_5	11,000-12,000 mg/L
TOC	4,800-5,200 mg/L

The levels of contaminants could be lower than those shown above, depending on the specific catalyst employed and whether or not chemicals recovery from the condensate is practiced.

Methanol synthesis wastewaters (Stream 237) generated by distilling crude methanol to obtain a fuel grade methanol product are estimated to have the following gross characteristics (5):

Production rate	1.5-5.3 m^3/hr
Alcohols	17,000-36,000 mg/L
COD	31,000-77,000 mg/L
BOD_5	22,000-54,000 mg/L
TOC	7,800-19,000 mg/L

The production rate of this wastewater is determined largely by the CO_2 content of the synthesis feed gas; as the level of CO_2 increases, the production rate of wastewater increases. The mass loading of propanol in this wastewater was assumed to be proportional to the quantity of carbon oxides converted (a relatively constant value for all coal cases). Therefore, the concentrations of propanol (and total alcohols) in this wastewater are inversely proportional to the wastewater production rate.

For all of the synthesis wastewaters listed above, the COD, BOD_5, and TOC values are calculated estimates. All BOD_5 values were estimated as 70 percent of the calculated COD values. COD and TOC values were calculated by assuming the organic acids were acetic acid, the ketones were acetone, and the alcohols were a mixture of methanol and propanol.

Methanation Condensate (Stream 228)

Water contained in crude SNG is condensed under pressure and is estimated to contain about 125 mg/L CH_4 and 100 mg/L of CO_2 (10). The quantity of methanation condensate generated depends on the synthesis operation and coal gasified. For the SNG synthesis facilities methanation condensate is generated at approximately 55 m^3/hr. In the indirect liquefaction facilities, the SNG coproduction unit is smaller and hence the quantities of condensate are smaller. Estimated flow rates range from 8 to 20 m^3/hr. Since this stream contains essentially no dissolved solids, it could be reusable as boiler feed water after depressurization and air or N_2 stripping to remove dissolved gases. For this reason, methanation condensate is more appropriately considered an internal process stream rather than a waste stream.

Removed CO_2 (Stream 231)

In most cases, residual CO_2 in the crude SNG from SNG synthesis facilities will not require removal. However, in indirect liquefaction facilities residual CO_2 in the crude SNG is higher and would be removed to obtain a pipeline quality gas. Since amine processes for CO_2 removal will remove some CO, H_2, and hydrocarbons, the CO_2 offgas from an amine process will also contain these constituents. The estimated composition of the CO_2 removal offgases is (5):

CO_2	91 vol %
CO	20 ppmv
H_2	200-1400 ppmv
CH_4	3 vol %
Nonmethane hydrocarbons	100-1100 ppmv
H_2	5.7 vol %
N_2	1700-3100 ppmv

The flow rate of the removed CO_2 stream is estimated around 24 to 83 kg-moles/hr for methanol and Mobil M synthesis. For F-T synthesis the flow rate is approximately 240 to 260 kg-moles/hr.

CO_2 Removal Wastewater (Stream 238)

The fractionation offgas sent to the CO_2 removal unit in an F-T synthesis facility is estimated to contain appreciable quantities of water. As a result, a wastewater is generated in the CO_2 removal step. The flow rate of this waste stream is estimated at approximately 0.4 m^3/hr. Composition data are not available for this waste stream, but it should contain only minor quantities of dissolved gases such as CO_2. As such it could be combined with the methanation condensate for reuse within the facility.

Dehydration Offgas (Stream 236)

The triethylene glycol regenerator offgas contains very small amounts of methane and the glycol solvent. No data are available to quantify these constituents. The offgas is estimated to have a flow rate of about 11 to 21 kg-moles/hr and to consist mostly of water vapor.

3.5 PRODUCTS AND BYPRODUCTS

The products/byproducts considered in this section include: 1) those produced as substitutes for petroleum-derived fuels or chemicals, 2) Lurgi byproducts, 3) sulfur and ammonia recovered as a result of air and water pollution control and, 4) excess coal fines. The substitutes for petroleum-derived fuels include methanol, Fischer-Tropsch liquids, Mobil M-Gasoline, LPG, and SNG. The Lurgi byproducts include tar, oil, naphtha, and phenols. The available data on the composition of each product and byproduct are presented in this section. These data are included to provide a general understanding of the nature of these products and byproducts. Because speciation data on these substances are limited, the data presented are not sufficient, nor intended, to provide a basis for risk evaluation judgements.

3.5.1 Methanol Synthesis Product

Methanol is produced primarily from natural gas. The composition of the crude product varies somewhat depending upon such factors as the specific synthesis process used, the synthesis pressure and temperature, and the H_2/CO ratio in the synthesis feed (33). The primary reaction in methanol synthesis is:

$$CO + 2H_2 \xrightarrow{\text{CATALYST}} CH_3OH + \text{heat}$$

However, a number of side reactions also take place which introduce impurities into the crude methanol. A representative, but not exhaustive, list of impurities which can be expected in crude methanol is presented in Table 3-25. An additional potential impurity not shown in the table is iron carbonyl. Under certain conditions the formation of this compound has been observed in the compression and synthesis sections of methanol plants (34). The use of special alloys could reduce or eliminate this occurrence.

TABLE 3-25. COMPONENTS REPORTED IN COMMERCIAL METHANOL (33)

- Dimethyl Ether
- Acetaldehyde
- Methyl Formate
- Diethyl Ether
- n-Pentane
- Propionaldehyde
- Methyl Acetate
- Acetone
- Methanol
- Isopropyl Ether
- n-Hexane
- Methyl Propionate
- Ethanol
- Methyl Ethyl Ketone
- t-Butyl Alcohol
- n-Propanol
- n-Heptane
- Water
- Methyl Isopropyl Ketone
- Acetal
- Isobutanol
- n-Butyl Alcohol
- Isobutyl Ether
- Diisopropyl Ketone
- n-Octane
- Isoamyl Alcohol
- 4-Methyl Amyl Alcohol
- n-Amyl Alcohol
- n-Nonane
- n-Decane

Synthesis gases derived from coal gasification have many similarities to those derived from natural gas reforming; however, they also have some important differences. Lurgi-derived synthesis gases have high concentrations of methane and other light hydrocarbons which may affect the activity and selectivity of traditional synthesis catalysts. Of course, operating experience is needed to assess whether these differences will have an impact upon product purity.

Table 3-26 shows an estimated composition of a crude methanol (Stream 107) made from coal. The amounts and types of impurities present will vary somewhat depending upon the specific synthesis process used and process conditions. However, water is expected to be the largest single impurity (5 percent) with all others comprising less than one percent. Several methods for purifying methanol are currently available (33), and the degree of methanol purification will largely be determined by user needs. Thus, coal-derived methanol in commerce may range in purity from about 95 percent pure in the case of the crude product to 99.85 percent pure for Grade AA methanol.

TABLE 3-26. ESTIMATED COMPOSITION OF CRUDE METHANOL (Stream 107) FROM COAL (24)

Compound	Concentration
CH_3OH	94.6 wt %
C_2H_5OH, C_3H_7OH and C_4H_9OH	2800 ppm
$(CH_3)_2O$	150 ppm
Nonmethane HCs	600 ppm
H_2O	5.0 wt %

3.5.2 Fischer-Tropsch Liquid Products

The crude Fischer-Tropsch synthesis product is composed primarily of straight-chained paraffinic and olefinic hydrocarbons (35). Minor quantities of aromatic, naphthenic, and branched-chain hydrocarbons are also present, along with small amounts of oxygenated compounds such as alcohols, aldehydes, ketones, and acids, most of which have fewer than five carbon atoms (36). The crude F-T product can be refined into several different products including LPG, gasoline, diesel oil, heavy oil, methanol, acetone, methyl ethyl ketone (MEK), and heavy alcohols. Much of the chemical composition data presented here is based on analyses of products from the commercial-scale Fischer-Tropsch synthesis plant which is currently operating in Sasolburg, South Africa.

Limited data on the composition of gasolines (Stream 100), diesel oils (Stream 101), and heavy oils (Stream 102) from F-T synthesis indicate that they are essentially nitrogen-and-sulfur-free (37). Crude Fischer-Tropsch gasoline requires upgrading prior to its use as a motor fuel. Table 3-27 shows the estimated chemical composition, by compound class, of the finished Fischer-Tropsch gasoline. The aromatics content (17%) is lower than that of typical petroleum gasolines (23-26%). The saturates content is similar to that of petroleum-derived gasoline, but the olefins content is much higher. The estimated Reid Vapor Pressure of 69 kPa for finished Fischer-Tropsch gasoline is within the range of values (48 to 100 kPa) for typical petroleum gasolines (41).

Table 3-28 shows the distribution of the oxygenated byproducts from fluid bed Fischer-Tropsch synthesis before further refining. At the SASOL plant, the aldehydes are hydrogenated and methanol is reported to be used on site as Rectisol solvent makeup. Ethanol, propanol, butanol, pentanol, acetone,

TABLE 3-27. ESTIMATED COMPOSITION OF FINISHED INDIRECT COAL LIQUEFACTION UNLEADED GASOLINES AND TYPICAL PETROLEUM GASOLINES

Component	Fischer-Tropsch Unleaded Gasoline (Refs. 5, 37)	Finished Unleaded Mobil-M Gasoline (Ref. 5)	Crude Mobil M-Gasoline (Ref. 5)	Petroleum-Derived Gasolines (Refs. 38, 39, 40)
Saturates, vol%	63	60	56	56-69
Olefins, vol%	20	11	13	4-8
Aromatics, vol%	17	29	30	23-36
Sulfur, wt%	Nil	Nil	—	0.014-0.417
Nitrogen, wt%	Nil	--	—	0.50-0.49
Oxygen, wt%	—	—	—	0.18-0.22

-- Indicates no data available.

TABLE 3-28. DISTRIBUTION OF OXYGENATED BYPRODUCTS FROM FLUID-BED FISCHER-TROPSCH SYNTHESIS (37)

Component	Wt %
Acetaldehyde	3.0
Propionaldehyde	1.0
Acetone	10.6
Methanol	1.4
Butyraldehyde	0.6
Ethanol	55.6
Methyl Ethyl Ketone	3.0
i-Propanol	3.0
n-Propanol	12.8
2-Butanol	0.8
EEK-MPK	0.8
i-Butanol	4.2
n-Butanol	4.2
n-Butylketone	0.2
2-Pentanol	0.1
n-Pentanol	1.2
C_6+ alcohols	0.6

methyl ethyl ketone, and a higher alcohol fraction are distributed commercially (37). SASOL also converts propylene and butylene from the light ends recovery to gasoline by polymerization over a solid phosphoric acid catalyst. The propane and butane are sold as LPG (42).

3.5.3 Mobil M-Gasoline

The Mobil M-Gasoline synthesis product is fractionated into a gasoline (Stream 108) and an LPG product (Stream 109). Table 3-27 shows the estimated composition of the finished Mobil M-Gasoline. It can be seen from this table that the olefins content of the Mobil M-Gasoline is higher than that of petroleum gasoline, while the saturates and aromatics contents are within the ranges found in petroleum gasolines. The benzene content of the finished Mobil M-Gasoline is also reported to be less than the one percent by volume which is typical of petroleum gasolines (41). As was mentioned earlier, iron carbonyl could be present in trace quantities in the methanol feed. It is, however, expected that any carbonyls in the methanol feed would be trapped by the gasoline synthesis unit's zeolyte catalyst and thus would not be present in the gasoline product.

Table 3-29 shows the blending compounds of an estimated finished gasoline product in a conceptual design of a Lurgi-based, Mobil M-Gasoline plant. It

TABLE 3-29. ESTIMATED BLENDING COMPONENTS FOR MOBIL M-GASOLINE (25)

Component	Wt %
Mixed butanes	2.4
Alkylate	3.2
Stabilized Gasoline	87.8
Hydrotreated Gasifier Naphtha	6.6
	100.0

can be seen that the stabilized gasoline fraction constitutes almost 88 weight percent of the finished gasoline and hydrotreated Lurgi naphtha constitutes nearly 7 percent. The estimated Reid Vapor Pressure of the finished gasoline is 69 kPa (5), which is within the range of values for typical petroleum gasolines (48 to 100 kPa) (41). The finished gasoline is reported to contain essentially no sulfur (5). The stabilized gasoline fraction from the synthesis unit may also be used for blending with petroleum gasoline. Although the chemical composition of the stabilized gasoline component of the finished gasoline product is fairly well characterized, no actual data on the chemical composition of the finished gasoline liquid or its vapors are yet available.

3.5.4 Substitute Natural Gas (SNG)

The primary constituent of the SNG product is methane with smaller quantities of H_2, CO, CO_2, N_2, and Ar. Coproduct SNG from liquids synthesis also contains minor amounts of low molecular weight hydrocarbons. Standards for pipeline gas generally require that the CO content be less than 1000 ppmv, and it is expected that the crude SNG product would be sufficiently upgraded, if necessary, to meet this criterion. Trace quantities of metal carbonyls may be produced during catalytic methanation, during gasification, or by reaction of CO and Ni or Fe in piping. Nickel carbonyl at concentrations above 0.01 ppmv was reported in product gas from the Lurgi gasifier at Westfield, Scotland (34). However, operators of the Lurgi gasifier at Sasol, South Africa, report that carbonyls are not present in measurable concentrations (less than about 1 ppbv) in the product gas from that facility (43). And, recent data from the Kosovo, Yugoslavia, Lurgi-type facility indicate that carbonyls are not present in gasifier gases to any appreciable extent in the desulfurized gases leaving the Rectisol unit (3).

3.5.5 LPG

LPG from both F-T (Stream 106) and Mobil (Stream 109) synthesis will consist primarily of propane and butane with smaller quantities of ethane, methane, and short-chain olefins. It is not expected that coal-derived LPG will be significantly different in chemical composition than petroleum-derived LPG. However, this has not been verified with product composition data from commercial-scale production facilities.

3.5.6 Lurgi Gasification Byproducts

Lurgi gasification generates several byproducts including tar, oil, naphtha, and crude phenol. Because Lurgi byproducts have a high energy content, they may be used as auxiliary fuel sources at the plant site or they could be gasified (in a suitable gasifier) to produce additional synthesis gas. However, the byproducts also may have value in the marketplace as fuel oil substitutes, gasoline blending stocks, or as chemical feedstocks. The available information on the composition of these substances is presented below.

Lurgi Tars (Stream 111)

Only limited data are available on the characteristics of byproduct tars. These data are summarized in Table 3-30. Some data are available for selected polynuclear aromatic (PNA) compounds in Kosovo tars (3). These data are shown in Table 3-31. Some composition data are also available for the tars produced in the Synthane coal gasification process (44). The Synthane data, which are presented in Table 3-32, are indicative of the type of substances which would also be expected in the Lurgi tars.

TABLE 3-30. AVAILABLE DATA ON THE CHARACTERISTICS OF BYPRODUCT TARS

	Rosebud[a]	Illinois No. 6[a]	Westfield Coal (low rank)[b]	Kosovo Lignite[c]
Specific gravity, g/cm³	1.035	1.145	1.124–1.126	1.06
Dust, wt %	22.0	4.5		
Phenols, wt %	5.3	2		3.9[d]
Ultimate Analysis				
(dry, dust free), wt %				
Carbon	83.1	85.5		81
Hydrogen	7.7	6.4		8.3
Nitrogen	0.6	1.2		1.3
Sulfur	0.3	1.7		0.5
Ash	0.1	<0.1		0.2
Oxygen (by diff)	8.2	5.2		7.7
Higher Heating Value, MJ/kg	36.8	36.9		37.3
Viscosity, centistokes	396	1336	120	
Distillation Range, %				
to 210°C			1.1–1.2	
210°C to 230°C			1.2–1.6	
230°C to 270°C			9.8–11.1	
270°C to 300°C			6.3–7.2	
300°C to 330°C			27.7–28.6	
Residue and losses			49.6–50.7	
Water			1.8–2.1	
Tar Acids, wt %			7.1–10.7	
Free Carbon, wt %			2.16–1.38	
Ash, wt %			0.16–0.22	
Sulfur, wt %			0.77–0.78	

[a] Reference 1.
[b] Reference 26.
[c] Reference 3.
[d] Summation of identified phenolic compounds.

TABLE 3-31. POLYNUCLEAR AROMATIC COMPOUNDS FOUND IN BYPRODUCTS FROM A LURGI-TYPE GASIFIER IN KOSOVO, YUGOSLAVIA[a]

Component	Heavy Tar	Light Tar	Medium Oil	Naphtha
Benz(a)anthracene	500	490	160	<0.1
7,12-dimethylbenz(a)anthracene	1300	1100	62	<0.1
Benzo(b)fluoroanthrene	320	310	120	<0.1
Benzo(a)pyrene (BAP)	240	210	68	<0.1
Dibenzo(a,h)anthracene	14	23	6.6	<0.1
3 methylcholanthrene	<1	26	<1	<0.1
252 Molecular Weight Group (as BAP)	1000	950	280	<0.1

[a] From Reference 3. Units are mg/kg.

TABLE 3-32. COMPOSITION OF BENZENE SOLUBLE TARS PRODUCED IN THE SYNTHANE GASIFICATION PROCESS (44)

Compound/Class	Type/Origin of Coal Bituminous (Illinois)	 Lignite (N. Dakota)	 Subbituminous (Montana)	 Bituminous (Pennsylvania)
	Volume %			
Mono Aromatics				
Benzene	2.1	4.1	3.9	1.9
Phenols	2.8	13.7	5.5	3.0
Di Aromatics				
Naphthalenes	11.6	19.0	15.3	16.5
Indanes/Indenes	10.5	5.0	7.5	8.2
Naphthols and Indanols	0.9	11.4	11.1	2.7
Tri Aromatics				
Phenylnaphthalenes	9.8	3.5	6.4	7.6
Acenaphthenes	13.5	12.0	11.1	15.8
Fluorenes	9.6	7.2	9.7	10.7
Anthrancenes/Phenanthrenes	13.8	10.5	9.0	14.8
Acenaphthols	—	2.5	4.9	2.0
Phenanthrols	2.7	—	0.9	—
Tetracyclic Aromatics				
Pericondensed (benzanthracenes, chrysene)	7.2	3.5	4.9	7.6
Catacondensed (pyrene, benzphenanthrenes)	3.0	1.4	3.0	4.1
Pentacyclic Aromatics	trace			trace
Heterocyclics				
Dibenzofurans	6.3	5.2	5.6	4.7
Dibenzothiophenes and Benznaphthothiophenes	6.2	1.0	1.5	2.4
N-Heterocyclics	10.8	3.8	5.3	8.8

Lurgi Oils (Stream 112)

The available characterization data for byproduct oils are summarized in Table 3-31 and 3-33. With respect to the PNAs shown in Table 3-31, many of the same constituents are present in both the tars and oils. In general though, lower concentrations of these constituents are found in the oils.

Lurgi Crude Phenols (Stream 113)

Table 3-34 presents the estimated composition of the crude phenol byproduct. The Phenosolvan solvent is expected to extract organics other than phenols which are present in the gas liquor; thus, byproduct crude phenol is expected to also contain small quantities of non-phenolic organics.

Lurgi Naphtha (Stream 114)

Lurgi naphtha is similar to petroleum-derived naphtha in that the principal constituents include benzene, toluene, and olefins. Table 3-35 presents composition data on Lurgi naphtha from the Westfield facility (26). Additional characterization data for byproduct naphtha are summarized in Tables 3-31 and 3-36. As indicated, Lurgi naphtha contains almost 90 weight percent aromatic compounds. Lurgi naphtha also contains significant quantities of dissolved gases including mercaptans, HCN, and H_2S as indicated by data for naphtha storage tank vent gases at the Kosovo plant (3).

3.5.7 Ammonia and Sulfur (Streams 115 and 116)

Ammonia is recovered as a byproduct in the treatment of condensates by steam stripping. The ammonia recovered may contain trace quantities of other substances (e.g., thiocyanates, phenols), although no actual data are currently available on the impurities present in the byproduct ammonia.

TABLE 3-33. AVAILABLE DATA ON THE CHARACTERISTICS OF BYPRODUCT OILS

	Rosebud[a]	Illinois No. 6[a]	Westfield Coal (low rank)[b]	Kosovo Lignite[c]
Specific gravity, g/cm^3	0.937	1.015	0.975-1.005	0.97
Dust, wt %	0.4	0.8		
Phenols, wt %	19.1	20.1		12.0[d]
Ultimate Analysis (dry, dust free), wt %				
Carbon	81.3	84.8		81.1
Hydrogen	9.2	7.8		8.9
Nitrogen	0.5	0.7		1.0
Sulfur	0.5	2.4		0.8
Ash	<0.1	<0.1		<0.1
Oxygen (by difference)	8.5	4.3		8.2
Higher Heating Value, MJ/kg	39.4	38.3		39.8
Viscosity, centistokes	4	5		
Distillation Range, °C				
5 vol. %	140	164	183-198	
20 vol. %	178	198	190-207	
40 vol. %	207	218	211-223	
60 vol. %	231	238	235-239	
80 vol. %	270	280	274-278	
95 vol. %	297[e]	331[f]	350-354	
Tar Acids, wt %			16.5-32.8	
Pyridine Bases, wt %			1.3-3.3	
Sulfur, wt %			0.29-0.99	
Naphthalene, wt %			5.5-7.6	

[a] Reference 1.
[b] Reference 26.
[c] Reference 3.
[d] Summation of identified phenolic compounds.
[e] Cracked at 88.5 percent.
[f] Cracked at 92 percent.

TABLE 3-34. AVAILABLE DATA ON COMPOSITION OF CRUDE LURGI PHENOLS (26)

Phenol Class/Compound	From Tarry Gas Liquor	From Oily Gas Liquor
Monohydric phenols		
Phenol	35	60
Cresols	13	20
Xylenols	3	8
Catechols	39	7
Resorcinols	10	5

Units are weight percent.

TABLE 3-35. COMPOSITION OF NAPHTHA PRODUCED AT THE WESTFIELD LURGI FACILITY (26)

Compound/Class	Concentration (wt %)
Paraffins and Olefins	10.71
Aromatics	
Benzene	19.56
Toluene	28.40
Xylene and ethylbenzene	14.7
Ethyl toluene	2.69
Trimethyl benzenes	11.8
Styrene	1.07
Indane	1.43
1,2-benzofuran	1.09
Indene	5.37
Naphthalene	1.40
Thiophenes	1.77
TOTAL	100

TABLE 3-36. AVAILABLE CHARACTERIZATION DATA FOR BYPRODUCT NAPHTHA

	Westfield Coal (Low Rank)[a]		Kosovo Lignite[b]
Specific Gravity, g/cm³	0.851	0.831	0.845
Distillation Range, °C			
Initial Boiling Point	69.2	69.5	
5 vol. %	82.5	80.5	
20 vol. %	92.0	86.0	
40 vol. %	102.5	91.0	
60 vol. %	117.5	98.5	
80 vol. %	145.5	115.5	
95 vol. %	189.5	160.0	
Paraffins, wt %	12.0	26.0	
Olefins, wt %	21.8	8.0	
Aromatics, wt %	65.4	65.9	
Sulfur, wt %	0.676	0.078	
Ultimate Analysis			
Carbon			86
Hydrogen			9.9
Nitrogen			0.2
Sulfur			2.2
Ash			NA
Oxygen (by difference)			2.2
Higher Heating Value, MJ/kg			41.6

[a] Reference 26.
[b] Reference 3.

Elemental sulfur is recovered as a byproduct in the treatment of concentrated acid gases for air pollution control. The recovered sulfur may be contaminated with a number of impurities. When the Stretford process is employed, the byproduct sulfur contains traces of vanadium, thiosulfate, and thiocyanate. Sulfur from the Claus process may contain carbonaceous materials to the extent that the byproduct is at times termed "black sulfur". Depending on site-specific factors, the sulfur may be saleable, require additional processing to produce a saleable product, or may need to be disposed as a waste.

3.5.8 Excess Coal Fines

Because the Lurgi gasifier requires a sized coal, the coal preparation operation will always generate some quantity of coal fines. Most proposed Lurgi-based facilities use these coal fines as fuel for steam and power generation. Depending on the physical properties of the ROM coal and the auxiliary boiler fuel requirements, excess coal fines may be generated.

A variety of methods are potentially available to handle these excess fines. They could be:

- combusted on site to produce electricity or steam for sale to offsite users,
- gasified in a reactor capable of handling coal fines to produce additional synthesis gas,
- sold as a byproduct,
- disposed of as a solid waste, or
- possibly pelletized to make a suitable feed for the Lurgi gasifiers.

3.6 AUXILIARIES

A number of nonpollution control auxiliary processes are associated with Lurgi-based synthetic fuels facilities. Included are raw water treatment, steam and power generation, process cooling, oxygen production, and product/byproduct storage. Sections 3.6.1 - 3.6.5 below provide brief descriptions of the most important auxiliaries and define the expected characteristics of the major waste streams. Generally, waste streams from the auxiliary processes are not unique to Lurgi-based facilities.

3.6.1 Raw Water Treatment

Raw water makeup requirements for Lurgi-based synthetic fuels facilities are dependent on the quality of available makeup water, the characteristics of the coal gasified, the synthesis operations employed, and the degree of water recycle/reuse practiced as well as a variety of other factors. Detailed estimates of raw makeup water requirements were not made for the base plants considered in this manual. However, based on estimates of water requirements for the two major consumers of water in a Lurgi-based plant (steam generation and the process cooling system), raw water makeup requirements are estimated to be 900 to 1300 m^3/hr.

The approach to raw water treatment is the same for the three plant locations considered in this manual (i.e., Montana for Rosebud coal, Illinois for Illinois No. 6 coal, and North Dakota for Dunn Co., ND lignite), with treatment requirements dominated by the system requiring the highest quality makeup water (steam/power boiler). Figure 3-18 shows a typical treatment scheme for producing boiler feedwater. Systems with lower quality requirements may withdraw water after any step in the treatment process that meets their requirements. For example, cooling tower makeup could be supplied directly from the sedimentation/equalization ponds in cases where raw water is low in hardness,

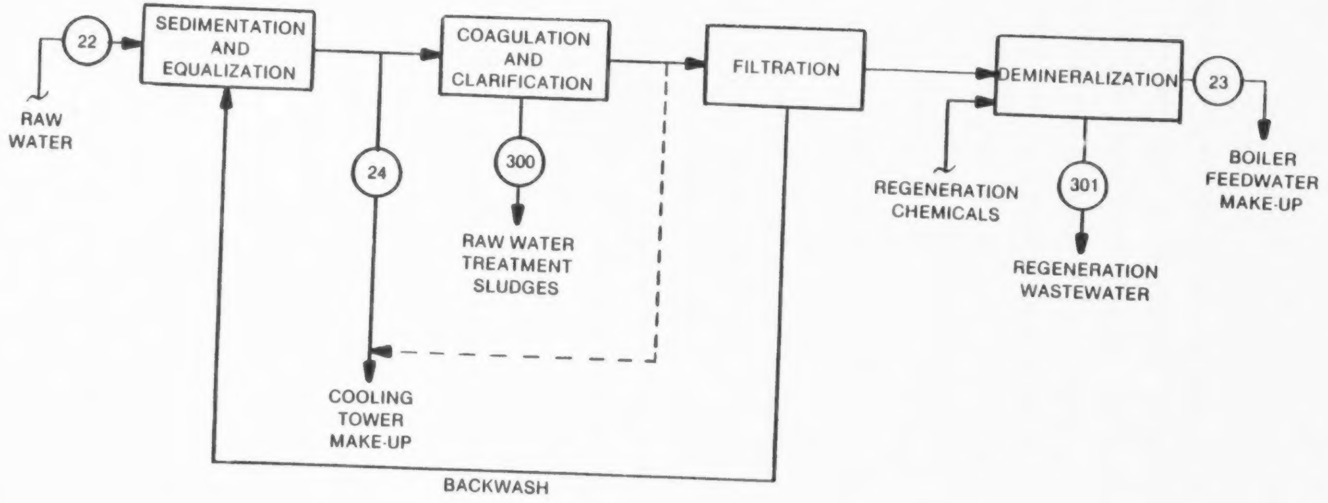

Figure 3-18. Typical raw water treatment system

alkalinity, and suspended solids. Where any of these constituents are present at high concentrations, raw water may require further treatment by softening, coagulation, clarification, or filtration prior to its use in the cooling water system.

The sedimentation and equalization step in Figure 3-18 includes withdrawal of water and storage in a reservoir. This storage provides a reliable supply of water to the facility independent of river flow, reduces the impact of daily water quality variations, and allows sedimentation of silts and other suspended material.

The raw water leaving the reservoir is treated in a sludge contact clarifier followed by a filter and a demineralizer. The clarifier is fed with lime, a coagulant, and a polymer to coagulate and/or flocculate fine suspended solids. The treated water then passes through a sludge bed of previously formed floc. This sludge contact enhances the agglomeration and settling characteristics of flocculated particles. An added benefit of this unit is a partial reduction in calcium alkalinity. A filter is also provided to protect the demineralizers from solids carryover from the clarifier. Excess sludge (Stream 300) consisting of calcium carbonate, magnesium hydroxide, and coagulated particulate matter is removed from the clarifier.

Demineralization is accomplished in two steps. Strong acid and strong base ion exchange units are used as the primary treatment step and a mixed bed polisher is used as the secondary step. Table 3-37 summarizes the estimated flow rates and characteristics of demineralizer regeneration wastes (Stream 301) from the strong acid and strong base exchangers. The mixed bed regeneration wastes will be comparable in dissolved solids to the compositions shown, but their flow will be intermittent and insignificant compared to those from the primary ion exchange step.

TABLE 3-37. ESTIMATED PRIMARY DEMINERALIZER REGENERATION WASTEWATER (Stream 301)

		Coal Type	
	Rosebud	Illinois No. 6	Dunn County
Flow Rate, m^3/hr	45	68	50
Constituent[a]			
TDS[b]	13,810	7,220	13,760
HCO_3^-	0	0	0
$SO_4^=$	9,700	5,000	9,500
Ca^{++}	160	160	160
Mg^{++}	360	90	200
Na^{++}	3,400	1,800	3,800
Cl^-	190	170	100
SiO_2	90	70	80
pH	1.7	1.7	1.8

[a] All units are mg/L except pH.

[b] Total dissolved solids calculated as a sum of the ions except SiO_2.

The flow rates shown in Table 3-37 are calculated as nine percent of the total raw water makeup flow rate to the boiler. Although a single value is indicated for each coal feed case, these wastewater flow rates will vary with the synthesis process. The flow rates shown for demineralizer regeneration wastewaters are averaged flows. In an actual plant the regeneration wastewaters will probably be produced on an intermittent, higher flow rate basis.

3.6.2 Steam and Power Generation and Process Heating

Lurgi-based synthetic fuels facilities will require boilers for steam generation and heaters for various process units. In addition to steam boilers and heaters, other auxiliaries could include dedicated gasifiers for producing low heating value fuel gas, electrical generating units, and gas turbines. The size of the steam boilers will be determined, in part, by both the gasifier steam needs and the extent to which steam drivers are used. Where electrical drivers are used, steam demand for electricity production may differ (qualitatively and quantitatively) from the case where steam drivers are used. When gas turbine drivers are used, steam requirements would be greatly reduced. A large number of possible auxiliary configurations is possible, and it is beyond the scope of this manual to perform the detailed engineering required to assess all of these configurations.

Auxiliary steam boilers are assumed to supply the facilities with all steam not produced in process waste heat boilers. Steam from the boilers is used for process purposes, for direct heating, in steam turbine drivers for motive power, and for generation of electric power. For certain purposes, steam superheating may be necessary.

Potential fuel sources for the steam boilers include coal fines, byproducts from the Lurgi gasification process (i.e., tars, oils, phenols, and naphtha), low-Btu fuel gas, and high energy content waste gases. As mentioned above, the size of the steam boilers will depend on a great number of factors. As a result, no attempt has been made in this manual to estimate the auxiliary boiler duties. As a rough approximation though, the energy requirements for the auxiliary boilers should range from 15 to 30 percent of the coal energy input to the gasifier (5,8,10). Table 3-38 presents the expected compositions of flue gases resulting from combustion of coal fines and Lurgi byproducts. Boiler flue gases (Stream 302) produced by the combustion of coal are not expected to present any new or unique pollution control problems beyond those encountered in the electric utility industry or other industries where large boilers are used. In general, this is true for flue gases derived from combustion of coal-derived fuels. However, the levels of trace heavy organics and trace elements which could be present in synfuel-derived flue gases are not well known.

Although complete data on the characteristics of bottom ash (Stream 406) for the subject coals are not available, their bulk composition would reflect the major inorganic elements found in the raw coal. Table 3-39 summarizes available data on the maximum levels of various constituents which have been reported in bottom ash and ash slurry waters from coal-fired boilers (46).

The quality and quantity of the boiler blowdown wastewater stream (Stream 303) will be dictated by the boiler drum operating pressure. In this analysis a boiler drum operating pressure of 10.3 MPa is assumed for all coal and synthesis process cases. For the base plants examined in this manual, boiler blowdown, after flashing, is estimated to be approximately 4000 to 5000 kg/hr.

An integrated facility would also have a number of small gas-fired heaters serving various process units (e.g., startup heaters). Such heaters would probably utilize sulfur-free waste gases from synthesis/fractionation operations as the most convenient fuel.

TABLE 3-38. ESTIMATED UNCONTROLLED AUXILIARY BOILER FLUE GAS COMPOSITIONS

	Boiler Fuel						
	Rosebud Coal	Illinois No. 6 Coal	Dunn Co. Lignite	Lurgi Tars[a]	Lurgi Oils[a]	Lurgi Phenols[a]	Lurgi Naphtha[a]
Component[b]							
CO_2, %	14.2	14.2	13.7	13.5	12.8	14.1	12.1
H_2O, %	10.0	7.3	14.7	7.5	8.7	7.1	9.2
N_2, %	72.4	75.0	68.4	75.6	75.2	74.4	75.3
O_2, %	3.2	3.3	3.0	3.4	3.3	3.3	3.3
SO_x (as SO_2), ppmv	1100	2200	790	150[c]	260[c]	[d]	1100[c]
NO_x (as NO_2), ppmv	660	520	370	270	120	130	120
CO, ppmv	60	50	75	45	45	50	45
HC (as CH_4), ppmv	30	25	<130	15	15	15	15
Particulates, g/Nm^3	12	8.6	4.5	0.70[e]	0.024	0.025	0.023
Flow rate, kg-moles/100 kg fuel	30	38	24	48	53	45	58
Energy input, MJ/100 kg fuel	2000	2660	1500	3760	3950	3200	4340

[a] Compositions shown are for Lurgi byproducts derived from gasifying Rosebud coal.

[b] Compositions shown are based on combustion with 20% excess air. Pollutant quantities are estimated using Reference 45.

[c] For byproducts from Illinois No. 6 coal, SO_2 is estimated as follows:
Tars - 910 ppmv
Oils - 1200 ppmv
Naphtha - 2100 ppmv

[d] Sulfur content of phenols is unknown but expected to be low.

[e] Assumes actual ash content of dust associated with tar is the same as ash content of parent coal.

TABLE 3-39. MAXIMUM MEASURED CONCENTRATIONS OF SELECTED COMPONENTS IN BOTTOM ASH AND ASH SLURRY (46)[a]

	Bottom Ash ppm	Slurry mg/L
As	40	0.12
Ba	4,000	3.0
Cd	250	0.052
Cr	270	0.17
Pb	35	0.2
Hg	4	0.026
Se	7.7	0.05
Ag	25	0.02
F-	100	16.2
Cl-	1,800	2,415
Cu	720	0.45
Fe	203,000	11.0
Mn	720	1.1
$SO_4^=$	—	2,300
Zn	950	2.7

[a] Based on a variety of coals.

3.6.3 Cooling Operations

A portion of the input energy to a synfuels plant will be rejected as waste heat. The exact amount of heat lost will be a function of both process design and operating practices and will be highly plant-specific. Further, the cooling water evaporation rate will be a function of the amount of wet versus dry cooling used at a given site. This, in turn, will be affected by design decisions based upon climatic factors and raw water costs. Since detailed designs and heat balances were not developed for this manual, some simplifying assumptions were made to develop representative cooling system loads.

The energy rejection rate from the cooling system was obtained by assuming that 40 percent of the thermal energy in the feed coal that is not recovered in the plant's products is rejected through evaporative cooling in a cooling tower (47). For purposes of estimating the heat rejection in the cooling tower, overall plant efficiencies of 54 to 64 percent were used (5,8). Under these assumptions, the variation in the energy rejection rates is directly reflected in the calculated cooling water evaporation rates for each base plant. Table 3-40 summarizes the waste stream rates expected to arise from cooling tower operations based on these assumptions. No basis was available to vary the cooling tower heat duty as a function of coal type. Thus, the data in Table 3-40 are assumed to apply to all three coals examined.

TABLE 3-40. WATER LOSSES FROM THE BASE PLANT COOLING TOWERS

	Synthesis Process		
	Methanol or SNG	Fischer-Tropsch	Mobil-M
Cooling water evaporation rate, Mg/hr	270	375	325
Cooling water blowdown flow rate, m³/hr[a]	66	92	79
Drift loss, Mg/hr)[b]	1.9	1.9	1.9

[a] At an assumed five cycles of concentration operation.
[b] Calculated as 0.01 percent of recirculation rate (48).

Discharges from the plant cooling systems consist of: blowdown water (Stream 307); evaporative losses (Stream 306), which include evaporated water and stripped gases; and entrained water (drift) (Stream 306). Table 3-41 summarizes the estimated cooling tower blowdown and drift characteristics (assumed to be the same composition) for a cooling system operating at 5 cycles of concentration. The blowdown/drift characteristics are intended to be typical of the concentrations expected for the plant locations when raw water is used as makeup. These characteristics do not necessarily represent optimum conditions for any given site (e.g., process waters after treatment could be used as cooling towers makeup). In addition to the concentrations of inorganic dissolved solids shown, scale and corrosion control additives would also be present in the blowdown/drift.

TABLE 3-41. ESTIMATED CHARACTERISTICS OF MAJOR COMPONENTS OF COOLING TOWER BLOWDOWN AND DRIFT[a]

Blowdown/Drift Constituents	Coal Type Rosebud	Dunn County	Illinois No. 6
Total Dissolved Solids[b]	2350	2280	1320
HCO_3^-	110	110	100
$SO_4^=$	1500	1450	740
Ca^{++}	260	250	180
Mg^{++}	180	100	45
Na^+	180	300	150
Cl^-	85	45	75
SiO_2	40	35	30
pH	7.5	7.5	7.5

[a] Concentrations are presented for operation at 5 cycles of concentration using raw water as makeup. All units are mg/L except pH.

[b] Total dissolved solids is the sum of the constituents shown.

3.6.4 Oxygen Production

Oxygen required by the Lurgi gasification process (Stream 4) is assumed to be produced by standard cryogenic air separation units. Oxygen purities used in the mass flow calculations are based on published data for oxygen purities used in gasification tests of the subject coals. It should be noted that the purity of oxygen utilized affects the quantity of the purge stream from the downstream synthesis process and thereby affects synthesis efficiency. Therefore, a trade-off exists between the energy required to produce high purity oxygen and the efficiency of the synthesis process. An analysis of optimum oxygen purities is beyond the scope of this manual. Oxygen requirements for the Lurgi-based synthetic fuels plants examined in this manual are estimated at 72,600, 110,000, and 83,600 kg/hr for Rosebud, Illinois No. 6, and Dunn County coals, respectively.

Production of oxygen does not directly generate waste streams requiring treatment, since chemical reactions do not take place in the air separation process nor are any chemicals added to the process streams. A gaseous waste stream containing mostly nitrogen and a liquid condensate are produced, but these streams are essentially pollutant free.

3.6.5 Product and Byproduct Storage

Onsite storage facilities will be provided for liquid products and Lurgi byproducts. For those liquids with very high vapor pressures (e.g., LPGs), pressurized storage vessels are assumed and hence no routine evaporative emissions are expected. For those liquids with relatively low vapor pressures (diesel oil and heavy fuel oil from F-T synthesis and Lurgi byproduct oil, tar, and phenol) fixed-roof storage tanks are assumed. All other liquids (methanol, gasoline, and Lurgi byproduct naphtha) are assumed to be stored in floating roof tanks with mechanical shoe seals.

For purposes of estimating potential emissions (Streams 308 through 311 and 313 through 317) from these storage vessels, a storage capacity equal to 15 days of production was assumed. Evaporative emissions were estimated, using correlations presented in References 45 and 49, for three locations in the U.S. - Southern Illinois; Dunn County, North Dakota; and Rosebud, Montana. Meteorological data for these locations were obtained from the National Climatic Atlas (50). Product and byproduct properties used in the emission correlations are summarized in Table 3-42. The resulting calculated emissions are summarized in Table 3-43 for both average annual conditions and worst case conditions (midsummer).

Data on the components of evaporative emissions associated with the storage of coal-derived liquid fuels are generally not available. However, limited data are available on evaporative emissions associated with petroleum gasoline storage as indicated in Table 3-44. In addition to the paraffins and olefins listed in this table, aromatics are expected to be present in evaporative emissions in the 1 to 1000 ppm range. Since the compositions of F-T and Mobil M-Gasolines are not dramatically different from those of petroleum gasolines, the gross characteristics of evaporative emissions are expected to be similar. Table 3-45 presents recent data on the evaporative emissions associated with the storage of byproducts at the Lurgi-type gasification plant in Kosovo, Yugoslavia (3). As indicated in the table, the vapors from the naphtha storage tank consist mostly of hydrocarbons heavier than C_6. Since Lurgi naphtha also contains high levels of mercaptans, HCN, and ammonia, these substances are found in the storage tank vapors. It should be noted that Lurgi crude tars, oils, and naphtha have somewhat higher vapor pressures than their petroleum-derived counterparts. This is due to the fact that Lurgi liquids are obtained by physical phase separation processes and still contain high levels of volatile components while petroleum liquids are usually "stabilized" to decrease volatility by fractionation and blending.

TABLE 3-42. ESTIMATED PRODUCT AND BYPRODUCT PROPERTIES

Product	Molecular Weight	Density kg/m³	Vapor Pressures, kPa South Ill. July	Ann.	No. Dakota July	Ann.	Montana July	Ann.
Methanol[a]	32	790	17	9	14	5	15	6
Gasoline	66	670	50	34	43	24	46	27
Diesel Oil	130	840	0.08	0.05	0.06	0.02	0.07	0.03
Fuel Oil	190	950	0.0006	0.0003	0.0004	0.0001	0.0005	0.0002
Naphtha	65	770	35	23	30	16	32	18
Lurgi Oil	190	950	0.9	0.5	0.7	0.2	0.8	0.3
Lurgi Tar	190[b]	950[b]	0.7	0.3	0.5	0.1	0.6	0.2
Phenols	190[b]	950[b]	0.8	0.4	0.6	0.1	0.7	0.2

Ann = Annual average.

[a] Properties of mixed alcohols are assumed to be equal to those of methanol.

[b] Assumed equal to that of Lurgi oil for mass emission estimate purposes.

Molecular weight, density, and vapor pressure properties were taken as those of similar petroleum products.

TABLE 3-43. ESTIMATED STORAGE TANK EVAPORATIVE EMISSIONS[a]

Product/ By-Product	Type of Tankage	Synthesis Process	South Ill.		North Dakota		Montana	
			July	Ann. Avg.	July	Ann. Avg.	July	Ann. Avg.
Mixed Alcohols	Floating Roof	F-T	14	9	15	6	17	7
Methanol	Floating Roof	Methanol or Mobil M	72	43	75	28	84	33
Gasoline	Floating Roof	F-T	31	28	47	26	49	29
Gasoline	Floating Roof	Mobil M	34	32	51	29	54	32
Diesel Oil	Fixed Roof	F-T	0.8	0.5	0.4	0.3	0.7	0.3
Heavy Fuel Oil	Fixed Poof	F-T	0.01	0.005	0.009	0.004	0.01	0.004
Lurgi Naphtha	Floating Roof	All[c]	7	7	12	6	12	7
Lurgi Oil	Fixed Roof	All	10	6	8	3	9	4
Lurgi Tars	Fixed Roof	All	29	14	22	5	26	8
Lurgi Phenols	Fixed Roof	All	7	3	5	1	6	2

[a] All data are in kg/day.
[b] Floating roof tanks are equipped with mechanical shoe seals.
[c] All means SNG, methanol, Mobil M-Gasoline and Fischer-Tropsch synthesis.

TABLE 3-44. COMPOSITION OF EVAPORATIVE EMISSIONS FROM GASOLINE STORAGE[a]

Compound	Vol. %[b]
Methane	1.13
Ethylene	0.001
Ethane	0.15
Propylene	0.03
Propane	0.82
Isobutane	3.03
Isobutylene	1.12
n-butane	3.53
cis-2-butane	0.84
Isopentane	6.18
n-pentane	2.89
Hexanes	0.44
Heptanes	0.16
Octanes	0.17

[a] From Reference 51.

[b] Balance is air.

TABLE 3-45. STORAGE TANK VENT DATA FROM KOSOVO PLANT[a]

Component	Light Tar Storage Tank	Medium Oil Storage Tank	Naphtha Storage Tank	Crude Phenol Storage Tank
Vol. %				
N_2	81	88	84-95	84
O_2	19	6.2	2.5-9.0	16
CO_2			NF-0.85	
C_2s			Tr-0.009	
C_3s			0.004-0.10	
C_4s			0.03-0.10	
C_4s			0.07-0.39	
C_6s			5.1-5.4	
Acid Gases	NF-0.4	06.-5.0		NF
Saturated HCs	NF	0.4		0.4
Unsaturated HCs	0.2-1.4	NF-1.2		NF
ppmv				
H_2S	230-890	1500-1600	NF-1600	NF
COS			NF	
CH_3SH			2400-4100	
C_2H_5SH			6700-12000	
Benzene			37000-38000	
Toluene			1600-2100	
Other Aromatics	Tr	Tr	57-63	NF-Tr
NH_3	100	75	NF-23	3.7
HCN			1100	

[a] From Reference 3.

[b] Tr means ~ 1 ppmv.

NF = less than 0.01 vol.% or less than 1 ppmv, as appropriate.

Single value data generally indicate only one data point available.

Blanks indicate no data available.

3.7 FUGITIVE AND MISCELLANEOUS WASTES

3.7.1 Fugitive Organic Emissions (Stream 233)

There are many potential sources of fugitive emissions in a Lurgi-based synthetic fuels facility. These sources include: pumps, compressors, inline process valves, pressure relief devices, open-ended valves, sampling connections, flanges, agitators, and cooling towers. Constituents of fugitive emissions include any of the volatile components present in the stream from which the emissions arise, including organics, H_2S, CO, NH_3, etc. No data are available on nonorganic fugitive emissions. However, extensive tests and measurements for fugitive organic emissions have been performed at petroleum refineries (52). As a result of this testing, average emission factors have been developed for fugitive emission sources such as pump seals, compressor seals, valves, etc. (53). These factors were applied to the product synthesis and upgrading operations of methanol, Mobil M, and F-T synthesis and to Lurgi byproduct handling in order to estimate fugitive organic emissions because these operations are quite similar to those in petroleum refining.

Fugitive emissions estimates were made by estimating the number of each type of emission source and applying the appropriate emission factor, with no adjustment for size, pressure, or flow rate. The number of pumps, compressors, and process units for each synfuel plant was estimated by correlating equipment lists to the proper size synfuel plant or adjusting the equipment counts reported in conceptual designs (5,18,54). Equipment spares were counted in determining the number of pumps and compressors, because it was assumed that spares usually contain fluid under pressure. In addition, it was assumed that eight pumps are used to handle the Lurgi byproduct tars, oils, phenols, and naphtha.

The process streams associated with each piece of equipment were classified with respect to percentage of hydrocarbon content and hydrocarbon type. Different factors were used for liquid streams containing light and heavy hydrocarbons. Liquid streams containing C_2 through C_9 hydrocarbons, naphtha, and other aromatic hydrocarbons were classified as light. Kerosene, diesel oil, and other heavy hydrocarbons were classified as heavy. All emission factors shown assume 100 percent hydrocarbon content, so all emission factors except those for compressors were multiplied by the actual hydrocarbon content for each process stream. Streams containing less than 10 percent hydrocarbons were neglected and those containing greater than 80 percent were considered to contain 100 percent. Gaseous streams were classified as either hydrocarbon or hydrogen depending on which was present in a greater percentage. The compressor seal emission factors for these two classifications were used as reported and not adjusted for percent hydrocarbon content. Table 3-46 summarizes the fugitive emission factors used.

Results of these fugitive emission calculations for Lurgi-based synthetic fuels facilities are given in Table 3-47. It should be noted that for the SNG production case, the only fugitive emissions estimated are those that arise from byproduct handling. Any fugitive emissions from the SNG synthesis operation would consist primarily of methane. It should also be noted that some fugitive emissions from the Lurgi gasification and gas purification operations are expected. However, there is not a good basis for estimating these additional emissions and hence they have not been estimated in this manual.

3.7.2 Non-Process/Intermittent Wastewater Streams

Fugitive process fluid leaks from sources such as pump seals, valves, and flanges will generate a composite waste stream with a highly variable flow and composition. In addition, drainage resulting from emergency process fluid

TABLE 3-46. FUGITIVE EMISSION FACTORS

Equipment Type	Classification	Emission Source	Source Emission Factor (kg/hr)	Quantity	Equipment Emission Factor[a] (kg/hr)
Pumps	Light Liquid Heavy Liquid	Pump Seals	.11 .021	1.4 x No. of Pumps	.154 .029
Compressors	Hydrocarbon Hydrogen	Compressor Seals	.64 .05	2 x No. of Compressors	1.28 .10
Process Units	All	Relief Valves	.086	6 x No. of Process Units	.516
Valves	Gas Service Light Liquid Heavy Liquid	Valves	.027 .011 .00023	41 x No. of Pumps	
Flanges & Fittings	All	Flanges & Fittings	.00025	164 x No. of Pumps	
Drains	All	Drains	.032	2.6 x No. of Pumps	

[a] Equipment Emission Factor equals Source Factors times Quantity.

TABLE 3-47. ESTIMATED FUGITIVE HYDROCARBON EMISSIONS

	Uncontrolled Emission Rates (kg/hr)			
	Fischer-Tropsch	Methanol	Mobil	SNG[a]
Pump Seals[b]				
Light Liquid Service	18	4.4	8.3	1.2
Heavy Liquid Service	0.5	0.2	0.4	–
Inline Valves				
Gas Service	37	9.9	18	2.2
Light Liquid Service	40	9.8	18	2.7
Heavy Liquid Service	0.1	0.1	0.1	–
Safety Relief Valves				
Vapor Service	25	5.2	11	–
Compressor Seals[b]				
Hydrocarbon	13	2.9	1.5	–
Hydrogen	1.8	–	–	–
Flanges	1.4	1.5	2.8	0.3
Drains	12	3.1	5.6	0.7
Totals	149	37	66	7.1

[a] Estimates are only for byproduct handling and storage.

[b] The uncontrolled emission factors for pumps and compressors represent emissions from each pump and compressor and not from each pump seal and compressor seal.

discharges or process area washdown/cleanup activities will contribute additional intermittent aqueous wastes. All of these wastes would normally be collected in a process sewer or oily waste sewer. The estimated flow rates of the combined wastewaters from these types of sources is 20 to 25 m³/hr. These process drainage (Stream 318) flow rate estimates are based upon refinery experience and are estimated as 2 percent of the total raw water makeup to the plant (55).

Both the flow rate and composition of these wastewaters will vary widely among the different plant sites. Of course, good housekeeping and maintenance practice will minimize these flows. These wastewaters will contain oil and grease, dissolved organics, dissolved inorganics, and particulate matter in widely varying concentrations. Because the characteristics of these wastewaters will be site-specific and highly variable with time, no composition estimates were developed for these streams.

Storm runoff water (Stream 319) flow rates will be a function of the surface drainage of the plant site and the annual rainfall. For calculation purposes, a plant site drainage area of 400,000 square meters was used. The annual rainfall rates for the assumed plant locations (50) and the resulting average storm runoff flow rate estimates are listed in Table 3-48.

TABLE 3-48. ESTIMATED AVERAGE STORM RUNOFF FOR ASSUMED BASE PLANT LOCATIONS

Coal Type	Annual Rainfall, cm[a]	Annual Average Storm Runoff, m³/hr
Rosebud	30	14
Illinois No. 6	100	47
Dunn County	40	18

[a] Reference 50.

The composition of storm runoff will vary with the frequency of rainfall occurrences and with time during a rainfall occurrence. The major contaminants are total suspended solids, oil, and grease. Because of the variable, site-specific nature of the composition of this stream, no attempt has been made to develop a detailed composition.

3.7.3 Equipment Cleaning Wastes

The two primary sources of equipment cleaning wastes at Lurgi-based facilities are process equipment (Stream 234) and boiler cleaning wastes (Stream 305). Process equipment cleaning wastes will result from periodic cleanup or maintenance of equipment such as heat exchangers, pumps, and pressure vessels. The volume of cleaning waste generated will be determined by the vessel volumes, frequency of cleanup, cleaning agent used, and rinsing requirements. Cleaning waste discharges are intermittent, short duration, high flow rate occurrences.

Boiler cleaning wastes will be generated on a one to four year cycle depending on plant maintenance practices. The large volume of the boiler can result in cleaning waste produced in excess of 3800 Mg over short periods of time. Boiler cleaning wastes will probably be the largest single source of cleaning wastes at a Lurgi-based facility.

The composition of equipment cleaning wastes will vary with the cleaning agents used and the materials being removed. Cleaning of process equipment generally includes the removal of oils, sludges, and waxy materials using alkaline solvents. Boiler cleaning is undertaken to remove inorganic (scaling) materials and metal corrosion products with acidic and alkaline cleaning agents. Rinse volumes from both process and boiler cleaning wastes contain lower contaminant concentrations but can amount to 2 to 5 times the volume of the cleaning waste. Treatment of these wastes is difficult because of their complex composition. Despite the intermittent and large volumes of waste generated, when considered on an annual average basis, cleaning wastes are produced at relatively low flow rates compared with other wastewaters generated in a Lurgi-based facility.

3.8 WASTE STREAM/CONTROL TECHNOLOGY INDEX

The preceeding parts of this section have presented a compilation of data (both calculated and test data) on the uncontrolled or primary waste streams expected to be produced by Lurgi-based synfuels facilities. Section 4 of this manual presents information on the available control techniques for these primary waste streams.

To aid users in finding characterization data and control technology information for any waste stream addressed in this manual, a stream number index and a cross reference index were developed. The stream number index is presented in Table 3-49. The waste stream cross reference index is presented in Table 3-50; for each primary waste stream, it indicates where in Section 3 characterization data can be found and where in Section 4 control technology information can be found. The waste streams in Table 3-50 are grouped by the operation or auxiliary process from which they originate and then further grouped within each operation by media, i.e., gaseous, aqueous, or solid.

Table 3-51 presents information similar to that in Table 3-50, but for residuals or secondary wastes streams, identified in Section 4, i.e., those resulting from use of pollution control techniques. The entries in Table 3-51 are not meant to imply that those streams will be necessarily found in Lurgi-based facilities, but only that if the control techniques listed are used, then those streams will be produced.

TABLE 3-49. STREAM INDEX

Process Streams		Products/Byproducts	
Stream Number	Stream Name	Stream Number	Stream Name
1	Run of mine (ROM) coal	100	Gasoline
2	Prepared coal to gasifier	101	Diesel oil
3	Steam to gasifier	102	Heavy fuel oil
4	Oxygen to gasifier	105	Mixed alcohols
5	Raw Lurgi gas	106	F-T LPG
6	Shift feed gas	107	Crude methanol
7	Shift bypass gas	108	Mobil gasoline
8	Shifted gas	109	Mobil LPG
9	Combined gas after shift	110	Moisture free SNG
10	Quenched Lurgi gas to acid gas removal	111	Tar
11	Acid gas removal product gas	112	Oil
12	Sulfur-free synthesis gas	113	Phenol
14	F-T purge gas	114	Naphtha
15	Methanator product	115	Ammonia
16	CO_2-free SNG	116	Sulfur
18	Methanol purge gas	117	Fuel grade methanol
19	Crude Mobil M-gasoline synthesis product		Primary Waste Streams
21	Coal fines	200	Dust from ROM coal storage
22	Raw water	201	Coal pile runoff
23	Boiler feedwater	202	Dust from coal preparation
24	Cooling tower makeup	204	High-pressure coal lockhopper gases

(Continued)

TABLE 3-49. (Continued)

Primary Waste Streams	
Stream Number	Stream Name
205	Low-pressure coal lockhopper gases
206	Ash lockhopper gases
207	Hot ash
208	Transient waste gases
209	Gas liquor depressurization gases
210	Gas liquor
211	Shift catalyst regeneration/decommissioning off-gases
212	Spent shift catalyst
213	H_2S-lean acid gases (nonselective Rectisol)
214	CO_2-rich acid gases (selective Rectisol)
215	H_2S-rich acid gases (selective Rectisol)
216	Methanol/water still bottoms
217	Spent sulfur guard
218	Spent F-T catalyst
219	F-T synthesis wastewater
220	Offgases from F-T product fractionation
222	Spent methanol catalyst
223	Spent Mobil catalyst
224	Mobil catalyst regeneration off-gases
225	Mobil synthesis wastewater
226	Mobil fractionator offgasess
228	Methanation condensate
229	Spent methanation catalyst
230	Methanation catalyst
231	CO_2 removal offgases
233	Fugitive organic emissions
234	Process equipment cleaning wastes
236	SNG dehydration offgases
237	Methanol synthesis wastewater
238	CO_2 removal condensate
300	Raw water treatment sludge
301	Demineralizer regeneration wastewaters
302	Boiler flue gas
303	Boiler blowdown
304	Boiler bottom ash
305	Boiler cleaning wastes
306	Cooling tower evaporation/drift
307	Cooling tower blowdown
308	Evaporative emissions from methanol storage

(Continued)

TABLE 3-49. (Continued)

Stream Number	Stream Name
Primary Waste Streams	
309	Evaporative emissions from gasoline storage
310	Evaporative emissions from diesel oil storage
311	Evaporative emissions from heavy fuel oil storage
313	Evaporative emissions from mixed alcohols storage
314	Evaporative emissions from Lurgi tar storage
315	Evaporative emissions from Lurgi oil storage
316	Evaporative emissions from Lurgi naphtha storage
317	Evaporative emissions from Lurgi phenols storage
318	Plant process drain wastes
319	Storm drain wastewater
Secondary Waste Streams	
400	Collected dust from pollution control
401	Coal lock vent gas scrubber blowdown
402	Ash lock vent gas scrubber blowdown
403	Quenched gasifier ash
404	Gasifier ash quench blowdown
406	Quenched boiler bottom ash
407	Boiler bottom ash quench blowdown
409	ADIP H_2S-rich offgases
410	ADIP hydrocarbon-rich offgases
411	Claus tail gas
412	Claus catalyst regeneration offgases
413	Spent Claus catalyst
414	Stretford tail gas
415	Stretford oxidizer vent
416	Stretford solution blowdown
417	Beavon tail gas
418	Spent Beavon or SCOT catalyst
419	Beavon catalyst decommissioning offgases
420	SCOT tail gas
421	SCOT recycle gas
423	Incinerated tail gases
428	Ammonia stripper overhead gases

(Continued)

TABLE 3-49. (Continued)

Secondary Waste Streams		Secondary Waste Streams	
Stream Number	Stream Name	Stream Number	Stream Name
431	Biological oxidation sludge	441	Boiler fly ash
433	Chemical precipitation sludge	442	Particulate-free boiler flue gas
435	Spent carbon	443	Particulate and SO_2-free boiler flue gas
436	Activated carbon regeneration offgases	444	FGD sludges/dry solids
437	Brine concentration offgases	445	W-L purge and bleed
440	Flue gases from wastewater incinerator	446	Regeneration offgas scrubber blowdown
		447	Collected particulates

TABLE 3-50. CROSS-REFERENCE INDEX FOR PRIMARY WASTE STREAMS

Waste Stream (Stream No.)	PCTM Section Reference For	
	Waste Characterization	Control Techniques
Coal Preparation		
• Gaseous Wastes		
– Dust From ROM Coal Storage (200)	3.1.4	4.1.5
– Dust From Coal Preparation (202)	3.1.4	4.1.6
• Aqueous Wastes		
– Coal Pile Runoff (201)	3.1.4	4.2.3
Lurgi Gasification		
• Gaseous Wastes		
– High Pressure Coal Lockhopper Gases (204)	3.2.4	4.1.2.1
– Low Pressure Coal Lockhopper Gases (205)	3.2.4	4.1.2.1
– Ash Lockhopper Gases (206)	3.2.4	NE
– Transient Waste Gases (208)	3.2.4	4.1.2.2
• Solid Wastes		
– Quenched Gasifier Ash (403)	3.2.4	4.3.2.1
Gas Purification and Upgrading		
• Gaseous Wastes		
– Gas Liquor Depressurization Gases (209)	3.3.5	4.1.2.3; 4.1.8
– Shift Catalyst Regeneration/Decommissioning Offgases (211)	3.3.5	4.1.3.1
– H_2S-lean Acid Gases (nonselective Rectisol) (213)	3.3.5	4.1.1.2; 4.1.8.2
– CO_2-rich Acid Gases (selective Rectisol) (214)	3.3.5	4.1.1.3
– H_2S-rich Acid Gases (selective Rectisol) (215)	3.3.5	4.1.1.1; 4.1.8.1
• Aqueous Wastes		
– Gas Liquor (210)	3.3.5	4.2.2.1; 4.2.2.5
– Methanol/Water Still Bottoms (216)	3.3.5	4.2.2.2; 4.2.2.5
• Solid Wastes		
– Spent Shift Catalyst (212)	3.3.5	4.3.5
– Spent Sulfur Guard (217)	3.3.5	4.3.5
Product Synthesis		
• Gaseous Wastes		
– Mobil Catalyst Regeneration Offgases (224)	3.4.3	4.1.3.2
– Methanation Catalyst Decommissioning Offgases (230)	3.4.3	NE
– CO_2 Removal Offgases (231)	3.4.3	4.1.2.4
– SNG Dehydration Offgases (236)	3.4.3	NE
• Aqueous Wastes		
– F-T Synthesis Wastewater (219)	3.4.3	4.2.2.3
– Methanol Synthesis Wastewater (237)	3.4.3	4.2.2.3
– Mobil Synthesis Wastewater (225)	3.4.3	4.2.3.3
– Methanation Condensate (228)	3.4.3	4.2.3
– CO_2 Removal Condensate (238)	3.4.3	4.2.3
• Solid Wastes		
– Spent F-T Catalyst (218)	3.4.3	4.3.5
– Spent Methanol Catalyst (222)	3.4.3	4.3.5
– Spent Mobil Catalyst (223)	3.4.3	4.3.5
– Spent Methanation Catalyst (229)	3.4.3	4.3.5

(Continued)

TABLE 3-50. (Continued)

Waste Stream (Stream No.)	PCTM Section Reference For	
	Waste Characterization	Control Techniques
Auxiliary Processes		
• Gaseous Wastes		
– Boiler Flue Gases (302)	3.6.2	4.1.4.1
– Process Heater Flue Gases	3.6.2	4.1.4.2
– Cooling Tower Evaporation/Drift (306)	3.6.3	NE
– Evaporative Emissions from Methanol Storage (308)	3.6.5	4.1.7.1
– Evaporative Emissions from Gasoline Storage (309)	3.6.5	4.1.7.1
– Evaporative Emissions from Diesel Oil Storage (310)	3.6.5	4.1.7.1
– Evaporative Emissions from Heavy Fuel Oil Storage (311)	3.6.5	4.1.7.1
– Evaporative Emissions from Mixed Alcohols Storage (313)	3.6.5	4.1.7.1
– Evaporative Emissions from Lurgi Tar Storage (314)	3.6.5	4.1.7.1
– Evaporative Emissions from Lurgi Oil Storage (315)	3.6.5	4.1.7.1
– Evaporative Emissions from Lurgi Naphtha Storage (316)	3.6.5	4.1.7.1
– Evaporative Emissions from Lurgi Phenols Storage (317)	3.6.5	4.1.7.1
• Aqueous Wastes		
– Demineralizer Regeneration Wastewaters (301)	3.6.1	4.2.3
– Boiler Blowdown (303)	3.6.2	4.2.3
– Boiler Ash Quench Blowdown (407)		4.2.3
– Cooling Tower Blowdown (307)	3.6.3	4.2.2.5; 4.2.3
• Solid Wastes		
– Raw Water Treatment Sludge (300)	3.6.1	4.3.2.5
– Quenched Boiler Bottom Ash (406)	3.6.2	4.3.2.2
Fugitive and Miscellaneous Wastes		
• Gaseous Wastes		
– Fugitive Organic Emissions (233)	3.7.1	4.1.7.2
• Aqueous Wastes		
– Process Equipment Cleaning Wastes (234)	3.7.3	4.2.3
– Boiler Cleaning Wastes (305)	3.7.3	4.2.3
– Plant Process Drain Wastes (318)	3.7.2	4.2.3
– Storm Drain Wastewater (319)	3.7.2	4.2.3

NE = Not evaluated.

TABLE 3-51. CROSS-REFERENCE INDEX FOR SECONDARY WASTE STREAMS

Pollution Control/Secondary Wastes	PCTM Section Reference For Waste Characterization	 Control Techniques	PCTM-Pollution Control Technology Appendices
Air Pollution Control Techniques			
Amine Enrichment		4.1.1	A-1
Hydrocarbon offgas (410)	4.1.1.2	4.1.8.1	
Claus		4.1.1	A-6
Catalyst regeneration offgas (412)		NE	
Sulfur (116)		4.3.3.1	
Spent catalyst (413)	4.1.1	4.3.5	
Stretford		4.1.1	A-7
Oxidizer vent gas (415)	4.1.1.2	4.1.8.2	
Purge liquids (416)	4.1.1.2	4.2.3	
Sulfur (116)		4.3.3.1	
Beavon		4.1.1	A-9
(See Stretford)	(See Stretford)	(See Stretford)	
Sour water (240)	4.1.1.2	4.2.2.4	
Spent catalyst (418)	4.1.1.2	4.3.5	
SCOT		4.1.1	A-10
Sour water (241)	4.1.1.2	4.2.2.4	
Spent catalyst (418)	4.1.1.2	4.3.5	
Wellman-Lord		4.1.1	A-10
Purge liquids (242)	4.1.1.2; 4.1.4.1	4.2.3	
Sulfur (116)	4.1.4.1	4.3.3.1	
Electrostatic Precipitators		4.1.4; 4.1.6	A-13
Dry solids (441)		4.3.2.3	
Venturi Scrubbers		4.1.4; 4.1.6	A-14
Scrubber blowdown		4.2.2.4; 4.2.3	
Dry Particulate Collectors		4.1.4; 4.1.6	A-11; A-12
Dry solids (400)		4.3.3.3	
Water Pollution Control Techniques			
Phenosolvan		4.2.1.2; 4.2.2.1	B-5
Spent filter media		NE	
PHOSAM-W		4.2.1.3; 4.2.2.1	B-8
Acid gases (428)	4.2.2.1	4.1.2.3	

(Continued)

TABLE 3-51. (Continued)

Pollution Control/Secondary Wastes	PCTM Section Reference For: Waste Characterization	PCTM Section Reference For: Control Techniques	PCTM-Pollution Control Technology Appendices
Water Pollution Control Techniques			
Activated Sludge		4.2.1.4; 4.2.2.1; 4.2.2.3	B-10
Offgases		NE	
Biological sludge (431)	4.2.2.1	4.3.4	
Activated Carbon Adsorption		4.2.1.5; 4.2.2.1; 4.2.2.3	B-15
Regeneration offgas (436)	4.2.2.1	4.1.3.3	
Spent carbon (435)	4.2.2.1	NE	
Thermal Oxidation		4.2.1.5; 4.2.2.1	B-17
Incinerator flue gas (440)	4.2.2.1	4.1.4.3	
Cooling Tower Oxidation/Concentration		4.2.1.5; 4.2.1.7; 4.2.2.1	B-18
Evaporation/Drift (306)		NE	
Chemical Precipitation		4.2.1.6; 4.2.2.1	B-19
Sludge (433)	4.2.2.1	4.3.2.5	
Forced Evaporation		4.2.1.7; 4.2.2.1	B-26
Noncondensible/Vent gases (437)		NE	
Deep Well Injection		4.2.1.8; 4.2.2.1	B-27
Surface Impoundment		4.2.1.8; 4.2.2.1	B-28
Evaporation		NE	
Leachate		NE	
Solid Waste Management Techniques			
Incineration		4.3.1.1; 4.3.4.1	C
Flue gases		4.3.4.1	
Ash		4.3.4.1	
Landfill		4.3.1.3	C
Leachate		4.3.1.3	
Land Treatment		4.3.1.3; 4.3.4.2	C
Volatile gases		4.3.4.2	
Leachate		4.3.4.2	

NE - Not evaluated.

SECTION 4.0

EVALUATION OF POLLUTION CONTROL TECHNOLOGY

At the present time, there are no Lurgi-based SNG or indirect coal liquefaction plants in commercial operation in the United States. In addition, very limited information is available which relates to pollution control processes used by the only significant Lurgi-based indirect liquefaction plant in commercial operation outside of the U.S. (i.e., the SASOL facilities). The emphasis on pollution control which has been incorporated into designs for most Lurgi-based facilities abroad is generally less than that which is anticipated for U.S. plants. Therefore, directly applicable performance data for most pollution control technologies are quite limited. The potential application of most pollution control technologies to waste streams identified in Section 3 has, therefore been extrapolated from their use in similar applications in industries such as petroleum refining, coke production, natural gas processing, coal cleaning, and electrical utilities. This section provides an evaluation of the control methods which may be adapted from other industries and from general pollution control practice, and a discussion of the principal limitations of these control methods in Lurgi-based synfuels plants. Control alternatives evaluated include process modifications (relative to existing designs) in addition to add-on control.

Approach

In this section a wide variety of potentially applicable pollution control technologies are discussed. In addition, illustrative examples of the application of individual control technologies to specific waste streams as well as the application of integrated systems of control technologies to specific waste streams are presented for each waste medium (i.e., gaseous, aqueous, and solid media).

Section 4
Pollution Control

Descriptions of the pollution control technologies presented in this section are based upon more detailed descriptions provided in the Control Technology Appendices for Pollution Control Technical Manuals. Performance data for control technologies have been obtained primarily from the open literature and supplemented by vendor-supplied data in some cases. The capabilities of various controls have not usually been assessed on a design-specific basis, but rather upon a generalized basis derived from available test results and/or engineering studies of the subject technologies. Example performance levels used for evaluation purposes encompass most of the published data. Therefore, only limited data referencing is provided in Section 4; detailed references are available in the Control Technology Appendices.

In many cases, performance has been, and can only be, estimated in terms of control of major constituents (e.g., volatile organic carbon) or gross parameters (e.g., COD) since often no information is available for removal efficiencies of specific substances. Further, even in those cases where substance-specific performance information exists for a control technology, accurate or complete characterization of the waste stream being treated may be lacking. In the final analysis, the capabilities of controls can be accurately evaluated only by testing at operating facilities or at smaller units from which data can be confidently extrapolated to commerical size. The performance estimates in this manual are believed to reflect the best information publicly available which is based on actual experience and on engineering analysis.

In providing example applications of pollution control technologies, waste streams unique to Lurgi-based synthetic fuels facilities and large volume/high loading waste streams have been emphasized. The source and characteristics of these waste streams have been detailed in Section 3, and those characteristics of principal significance with regard to the application of pollution control technologies are reiterated in this section. It should be noted, however, that Section 3 does not reflect the design of a specific facility, but incorporates key features of a number of existing and proposed facilities. Some of the waste streams identified in Section 3 may not be found in all facilities. Further in a specific facility, some streams encountered may differ significantly in size and characteristics from analogous streams discussed in this section, and controls other than those cited in the examples may be more appropriate. For these reasons, the reader is encouraged to consider design-specific waste stream characterization data whenever they are available, and to use the detailed Control Technology Appendices for estimating the applicability and performance of specific controls to waste streams. The control examples in this section emphasize the Rosebud subbituminous coal cases. Effects of coal characteristics and design modifications are discussed in cases where either may significantly influence control performance or cost.

Quantitative reliability data on pollution control processes in most industrial facilities, and in coal conversion facilities in particular, are generally not publicly available. Many of the operators who keep records on reliability feel that that information is proprietary to their business and hence do not make it publicly available. As a result, much of the publicly available information on process reliability consists only of relative judgments, such as "the process is highly reliable" or "no significant reliability problems have been encountered."

Because most of the pollution control technologies potentially applicable to synthetic fuels facilities have not been employed in these facilities, few directly related reliability data are available. Further, the overall characteristics and variability of waste streams in synthetic fuels facilities are often significantly different from those encountered in other industries. As a result, reliability data accumulated in other industries may not be applicable to coal conversion processes.

A large number of factors can affect the reliability of a process in a specific application, including:

1) The design of the equipment;

2) The presence of spares or redundant equipment pieces for critical parts of the process;

3) The variability of feed characteristics and operating conditions;

4) The skill of operators and their dedication to making the process work; and

5) The emphasis placed on corrective and preventive maintenance and the skill and dedication of the maintenance personnel

From an examination of just the above factors, it is obvious that even identically designed processes in identical applications can have different reliability records. It should also be noted that in essentially any industry, the introduction of a new process or the modification of an older process for application to a new stream can meet with unexpected problems relating to both design features and operating practices. Thus, some shakedown period must be expected during which process performance, efficiency, and onstream time will improve. Once a process is properly characterized for a specified application, reported reliability in terms of onstream time and performance levels may still vary among facilities. However, it can be anticipated that reliability will improve as experience is gained with individual systems and their applications, i.e., reliability will increase with time.

The reliability information presented in the rest of this section is in the form of general comments on the reliability of pollution control processes. The types of factors considered in developing these comments include 1) the complexity of the process (more complexity tends to indicate lower reliability), 2) the age of the process (the continued use of a process over a long period of time tends to indicate it can be designed and operated reliably), 3) the sensitivity of the process to changes in the characteristics of the feed stream (e.g. composition, flow rate, temperatures, pressure), etc. More detailed discussions of reliability and available reliability data are presented in the Control Technology Appendices for Pollution Control Technical Manuals.

Organization

The pollution control technology evaluations are presented according to the medium to which the technologies apply. Technologies applying to gaseous, aqueous, and solid waste media are discussed in Sections 4.1, 4.2, and 4.3, respectively. Included in each of these sections are 1) a summary of waste stream characteristics which are significant with respect to the application of pollution controls (detailed characterization estimates are presented in Section 3), 2) a brief description of the performance and costs of potentially applicable pollution control technologies, 3) examples of the performance ad cost of individual pollution control technologies applied to specific waste streams, and 4) examples of the performance and cost of integrated pollution control systems.

Gaseous waste streams may be categorized according to the principal pollutants which are present and, in general, different controls or groups of controls are applicable to each category. Therefore, the technology description and control examples are presented in Section 4.1 (Gaseous Medium) by the waste stream categories or source types to which they apply.

Source type categorizations may also be made for aqueous and solid wastes. Waste streams in these media, however, often lend themselves to treatment by control technologies which may be applicable to several individual source types or to combinations of source types. Therefore, in Section 4.2 and 4.3 (Aqueous Medium and Solid Waste Management, respectively) potentially applicable pollution control technologies are discussed at the beginning of the sections prior to the presentation of control examples.

Costing Methodology

Capital and operating cost estimates have been developed for the control processes discussed in this section. These cost estimates are based primarily on estimates contained in non-proprietary published literature. The estimates are provided to give the reader an indication of the costs of controls that are applicable to Lurgi-based synthetic fuels plants. It was beyond the scope of this document to develop detailed engineering designs necessary for highly accurate cost estimation.

There are three general factors that lead to uncertainties in the cost estimates provided. These are related to the assumptions used to develop material and energy balances, the level of accuracy of the published cost data used, and the general methodology used to apply the acquired cost data to the control processes addressed in this document.

Material and energy balances were derived mainly from 1) commercial synfuels tests and synfuels pilot plant studies, 2) data from analog industries, and 3) engineering calculations, as described in Section 3 and Appendices A and B in this volume. The level of accuracy in specifying the flow rates and quality of input streams to controls will affect the accuracy of the resulting cost estimates.

Sources of cost data used in this document are published costs for processes applied to similar streams in related industries, costs from published design studies for coal gasification plants, and vendor quotes. The accuracy of cost data taken from published sources is influenced by the details of the design upon which the cost was based, the cost methodology used, and the degree of similarity of the streams. In addition, the accuracy of the published estimates and definition of the components included in these estimates (e.g., contingency reserves, working capital, land) are not always specified in the reference. Thus, extrapolation of published costs to the stream being treated in this document will introduce uncertainties in the resulting estimates.

The general costing methodology used in this manual (see Appendix C for details) also introduces some uncertainties. Other estimators may choose to use different factors for components such as direct and indirect installation costs and interest during construction. In addition, available cost estimates were adjusted to a first quarter 1980 basis using chemical process construction escalation indices. It is therefore possible that recent advances in the state-of-the-art are not reflected in some of the resulting cost estimates.

As a result of the above influences, the accuracy of the cost information presented will vary from control to control. However, the cost information presented is believed to be adequate for the use intended.

The capital costs presented are total depreciable investments. Included in the total depreciable investment is 1) installed equipment costs (including the cost of delivered equipment and direct installation charges such as those for wiring, piping, labor, etc.), 2) indirect installation charges (including construction and engineering costs, contractor fees, and contingency), and 3) interest during construction. Startup costs are not included in the capital cost estimates presented, but could be a significant additional cost for new technologies such as as those examined in this PCTM. Total annualized costs presented include 1) labor and maintenance, 2) raw materials, utilities, chemicals, and catalysts, 3) overhead charges, and 4) capital-related charges (including interest on working capital, taxes, insurance, and capital recovery). The same methodology was used to calculate capital and annualized costs for both the base plant and pollution controls. Details of that methodology and other pertinent assumptions and bases which were used to develop the cost estimates are presented in Appendix C.

4.1 GASEOUS MEDIUM

Gaseous waste streams (or uncontrolled gaseous emissions) generated in Lurgi gasification facilities and originating from the main process train and from nonpollution control auxiliary processes were identified in Section 3. Table 4-1 summarizes the characteristics of these streams along with additional streams generated by pollution control processes in other media (primarily water pollution control). In terms of volume and pollutant loading, the most important streams in the subject facilities are Rectisol acid gases and combustion flue gases. Pollutants of primary concern are reduced sulfur species (H_2S, COS, and RSH), SO_2, and non-methane organics (or VOC - volatile organic compounds). Smaller volume waste gases include coal lock-hopper and transient waste gases, catalyst regeneration offgases, and depressurization/stripping gases. These streams contain the above pollutants and one or more of the following: HCN, NH_3, CO, and organic aerosols (possibly containing polycyclic organic matter). Additional sources of VOC are fugitive emissions from pumps, valves, and product/byproduct storage. Particulate matter (other than organic aerosols) originates from coal preparation operations and combustion units firing coal or high ash tars or oils.

The waste streams in Table 4-1 may be regrouped into two broad categories - those which are unique to gasification or synthesis operations and those which are not unique, being associated with auxiliary processes within an integrated facility. In Section 3, gaseous wastes were identified and characterized from the standpoint of their origin in an integrated plant. Table 4-2 is a regrouping of these waste streams according to the major types of potential pollutants which they contain. Streams unique to the subject facilities are primarily those containing reduced sulfur, non-methane organics, and smaller amounts of HCN and NH_3. These are 1) Rectisol acid gases, 2) depressurization and stripping gases, 3) gasifier transient waste gases,

TABLE 4-1. SUMMARY OF ESTIMATED GASEOUS STREAM CHARACTERISTICS IN LURGI-BASED FACILITIES

Stream Name	Constituent Concentration (Volume Percent Dry Basis)										Flow Rate (kmols/hr dry basis)
	H_2S	COS	RSH	SO_2	VOC	CO	NH_3	HCN	Particulate Matter	NO_x	
Streams from main process train											
Dust from coal preparation	—	—	—	—	—	—	—	—	Present	—	Intermittent and highly variable
High-pressure coal lockhopper gases	0.4-1	0.01	0.1	—	2	20	0.4-0.8	0.01	Present	—	760 (average)
Low-pressure coal lockhopper gas	0.4-1	0.01	0.1	—	2	20	0.4-0.8	0.01	Present	—	12 (average undiluted basis)
Waste gas from startups, shutdowns, and upsets	0.2-0.5	0.01	0.05	—	1	10	0.2-0.5	0.01	Present	—	2000 (maximum); 30 (average)
H_2S Lean acid gases/ nonselective Rectisol	1-3	0.01-0.03	0.01-0.5	—	2	1	<0.001	<0.01	—	—	6000 - 7000
CO_2-rich acid gases/ selective Rectisol	<0.01	<0.01	—	—	2	0.1	<0.001	<0.01	—	—	4000 - 6500
H_2S-rich acid gases/ selective	5-25	0.05-0.25	0.1-0.5	—	1-4	<0.1	<0.001	<0.1	—	—	300 - 2000
Shift catalyst decommissioning offgas	—	—	—	10-20	—	—	—	—	Present	Present	150 (maximum); 10 (average)
Streams from synthesis processing											
Methanation catalyst regeneration/decommissioning offgas	—	—	—	—	—	—	—	—	Present	—	Unknown; very infrequent
Mobil M-Gasoline catalyst regeneration offgas	—	—	—	—	Present	1	—	—	Present	Present	100 (maximum); 48 (average)

(Continued)

TABLE 4-1. (Continued)

Stream Name	Constituent Concentration (Volume Percent Dry Basis)										Flow Rate (kmols/hr dry basis)
	H_2S	COS	RSH	SO_2	VOC	CO	NH_3	HCN	Particulate Matter	NO_x	
Streams from synthesis processing (continued)											
Methanation condensate depressurization gases	—	—	—	—	—	—	—	—	—	—	Unknown
CO_2-rich gases from SNG production	—	—	—	—	1-3	0.1	—	—	—	—	50 - 100
Fugitive organics from process sources	—	—	—	—	Present	—	—	—	—	—	Intermittent and highly variable
Streams from auxiliary processes											
Flue gas from power generation	—	—	—	0.05-0.3	0.01	0.03	—	—	4-8 g/Nm³	Present	7000 - 20,000
Product and byproduct storage emissions	Present	—	—	—	Present	—	—	Present	—	—	Intermittent and highly variable
Streams from water pollution control processes											
Depressurization and stripping gases	0.4-1.0	—	Present	—	0.01-0.7	0.3-0.6	0.1-0.2	0.01-0.2	—	—	200 - 600
Activated carbon regeneration offgas	—	—	—	—	Present	1-5	—	—	Present	—	2000-2500 (maximum); 160-200 (average)
Wastewater incinerator flue gas	—	—	—	0.02-0.1	Present	Present	—	—	4-5g/Nm³	Present	3400 - 7300

Double dashes (—) indicate that the constituent is not present in any significant quantity in the subject stream.

TABLE 4-2. CATEGORIZATION OF GASEOUS WASTE STREAM IN LURGI GASIFICATION FACILITIES ACCORDING TO SOURCE TYPE

Source Type	Stream Name and Origin	Factors Affecting Flow Rate and Pollutant Loading
Reduced sulfur and VOC-containing gases		
Rectisol acid gases	Rectisol acid gases	Selective vs. nonselective H_2S and CO_2 removal; coal sulfur; and coal rank
Small volume and intermittent/transient waste gases	Depressurization and stripping gases (tar/oil separation and water pollution control)	Pressure of operation; may be coal specific but data are not available to determine relationships
	Gasifier transients (startup, shutdown, and off specification gases)	Not readily related to coal variables, would be highly design- and operation-specific
	Coal lockhopper gases (Lurgi gasifier)	Coal rank; lock pressurant; and process design
Transient process gases containing SO_2, CO, and/or particulates	Shift catalyst regeneration/decommissioning offgases	Degree of shift (SNG vs. liquids); regeneration frequency, but not especially related to coal variables
	Mobile M-gasoline catalyst regeneration offgases	Not related to coal variables; primarily a function of throughput
	Miscellaneous catalyst decommissioning offgases	Not related to coal; design and plant specific
Combustion gases containing SO_2, particulate, and NO_x	Boiler flue gases	Not unique to gasification plants; overall plant thermal efficiency; fuel mix, coal rank, ash, and sulfur content
	Process heater flue gases	Tend to be design/synthesis-specific; not related to coal parameters
	Wastewater incinerator flue gases	Fuel used, extent of wastewater concentration prior to incinerator
Fugitive VOC	Product/byproduct storage evaporative emissions	Syntheses and final product slate; Lurgi byproducts somewhat coal-specific
	Process equipment fugitives	Entirely plant specific; highly dependent upon synthesis and upgrading steps
Nonfugitive particulate	Coal handling and preparation	Coal physical properties and rank, but not related to gasification or syntheses
	Ash lockhopper vent gases	Coal ash content
Fugitive particulate	Coal storage	Coal physical properties, but not related to gasification or synthesis

and 4) coal lockhopper gases. Unique streams containing SO_2, VOC, CO, and/or particulates include shift and Mobil M-catalyst regeneration offgases, and emissions from storage and combustion of Lurgi byproducts. Nonunique streams found in all of the subject facilities would include coal combustion flue gases, coal preparation dust, product storage emissions, and process VOC emissions.

In the subsections which follow, controls which may be applicable to the above gaseous wastes are identified. For those technologies for which data are available, the expected performance and unit costs are provided. In many cases, control of gaseous pollutants involves both inherent process design features and tradeoffs among processes. Further, some waste gases would generally be combined for treatment rather than handled separately. Accordingly, example approaches to control of pollutants in integrated facilities are provided. Sufficient detail is included in these examples such that overall emissions reductions and costs can be seen. In the discussions below, emphasis is on the unique streams rather than on those streams for which information about control may be found in other documents.

4.1.1 Rectisol Acid Gases

As discussed in Section 3, Lurgi gasification plants would employ the Rectisol process(es) for removal of CO_2, sulfur compounds, and HCN from Lurgi gases. The regeneration of the methanol solvent produces waste gases enriched in these acid gases. Since low molecular weight organics and, to a lesser extent, carbon monoxide and hydrogen are also soluble in cold methanol, Rectisol acid gases will also contain these constituents. In terms of waste gas volume and loading, Rectisol acid gases are by far the largest source of uncontrolled sulfur (sulfur in this context refers to all sulfur species: H_2S, COS, CS_2, RSH, and SO_2) and VOC emissions in a Lurgi facility.

Approaches to treatment of Rectisol acid gases are aimed primarily at removal of H_2S and can be divided into three categories for discussion purposes: 1) pretreatment, 2) bulk sulfur removal, and 3) tail gas treatment. Partial or essentially complete control of non-H_2S sulfur, HCN, CO, and VOC can be realized either as an integral part of the sulfur control approach or as separate intermediate or add-on steps. Pretreatment of the acid gases serves two main functions: 1) to enrich acid gases for economical and efficient sulfur removal by Claus type sulfur recovery (streams which contain less than approximately 10% H_2S require enrichment for efficient and economical sulfur recovery in a Claus process); and/or 2) to remove impurities which can either detrimentally affect downstream pollution control processes or present nonsulfur emissions problems. Bulk sulfur removal is aimed at recovery of the majority of the sulfur contained in the gases. Tail gas treatment is aimed at control of smaller amounts of H_2S and other sulfur compounds (e.g., mercaptans and COS).

Since reduced sulfur compounds are the primary pollutant of concern in acid gases, sulfur control is the main focus of control approaches for this stream. However, other potential pollutants (HCN, CO, and VOC) are also present in acid gases and their control will be necessary to either reduce atmospheric emissions or to improve the performance of sulfur control processes. Control of nonsulfur species can involve the design of Rectisol, the design/operation of sulfur control processes, and/or the addition of other processing steps.

Pretreatment

Table 4-3 summarizes the key features of selective Rectisol and amine systems for enrichment of H_2S in acid gases. As discussed in Section 3, Rectisol systems can be designed to be either nonselective (no separation of CO_2 and H_2S during removal from Lurgi gas) or selective (removal such that an H_2S-rich gas and a CO_2-rich gas are generated). Thus, selective Rectisol itself may be considered as a pretreatment step for enrichment of the H_2S content of a portion of acid gases removed from Lurgi gas. Various levels of selectivity can be obtained in Rectisol designs depending on the relative economics of the Rectisol unit compared to the downstream Claus plant or other H_2S enrichment alternatives (e.g., amine systems).

The Rectisol selectivity assumed for analysis purposes in this document is based primarily upon data from an early, partially selective Rectisol unit at Kosovo, Yugoslavia. Licensers of Rectisol technology (Lurgi and Linde, West Germany) indicate that greater selectivity than assumed in this document can be obtained with Lurgi type feed gases, and that the issue is primarily one of economics, with hydrocarbon content of H_2S gases as an additional consideration for reliable Claus plant operation. Even with low sulfur feed gases, selective Rectisol units have been designed and built to obtain H_2S fractions suitable for Claus processing without further enrichment (15% or more H_2S).

Selectivity in Rectisol systems is obtained by sequentially absorbing H_2S and CO_2 present in the feed gas and separately regenerating the resulting H_2S-rich and CO_2-rich methanol streams. First, H_2S is removed from the feed gas by absorption in CO_2 saturated methanol. Carbon dioxide is subsequently removed by absorption in regenerated, H_2S-free methanol. Rich methanol from H_2S absorption is enriched in a fractional distillation column by removing a

TABLE 4-3. KEY FEATURES OF HYDROCARBON REMOVAL/H_2S ENRICHMENT PROCESSES

Process	Principle of Operation	Efficiency	Reliability/Limitations	Effects of High CO_2 in Feed Gas	General Comments
Selective Rectisol	Physical absorption with methanol at elevated pressure. Selectivity for H_2S obtained both during absorption and by concentrating H_2S in an enrichment column during solvent regeneration.	H_2S-rich acid gases are concentrated enough for Claus processing and contain most of the organics in the feed gas. Total sulfur levels in the CO_2-rich offgas can be as low as 10 ppmv.	High onstream factors are realized with existing Rectisol units. Energy requirements and costs can be high when both highly-enriched Claus feeds and nearly sulfur-free CO_2 fractions are desired. It is difficult to obtain Claus feeds without organics when such compounds are present in feeds.	High CO_2 makes both selective absorption and regeneration more capital cost and energy intensive. High CO_2 makes separation of COS more difficult, so that larger towers are needed to obtain a sulfur-free CO_2 fraction.	Selective Rectisol has seen wide commercial application in both oil gasification and entrained coal gasification. Suitable Claus feeds and sulfur-free CO_2 offgases are obtained even with low sulfur fuels. Existing selective applications have not involved feed gases with nonmethane organics.
DIPA (Di-isopropanol amine)	Chemical absorption at atmospheric pressure. Selectively absorbs H_2S over CO_2. Generates an H_2S-rich acid gas and a CO_2-rich acid gas. Also absorbs HCN and a small fraction of the COS.	H_2S-rich acid gas produced is concentrated enough for Claus processing. CO_2-rich acid gas contains the majority of HCs, COS, and mercaptans.	CO_2-rich acid gas stream contains sulfur compounds and organics which may require removal prior to discharge.	Reduces selectivity of CO_2 over H_2S and CO_2 over COS.	Applicable primarily for hydrocarbon gases. Some enrichment of H_2S also results. Capital costs for DIPA range from \$50 x 10^3 to \$330 x 10^3 per Mg sulfur removed per day, depending on the total flow, H_2S content, and degree of enrichment desired.
MDEA (Methyl Di-ethanol amine)	Chemical absorption at atmospheric pressure. Higher selectivity for H_2S over CO_2 than DIPA. Generates an H_2S-rich acid gas and a CO_2-rich acid gas.	H_2S-rich acid gases produced are concentrated enough for Claus processing. CO_2-rich acid gas contains the majority of HCs, COS, and mercaptans.	CO_2-rich acid gas stream contains sulfur compounds and organics. Residual sulfur levels not as low as with DIPA.	Has limited effect. CO_2 does not react directly with tertiary amines.	Limited commercial application to date. Selectivity for H_2S over CO_2 and the H_2S level in the treated gas are very sensitive to absorber temperature. Capital costs are similar to DIPA where high selectivity is not necessary. Tertiary amines are less capital intensive for selective applications.

portion of the absorbed CO_2. This enriched methanol is regenerated to yield an H_2S-rich acid gas. Rich methanol from CO_2 absorption is regenerated to yield a nearly sulfur-free, CO_2-rich acid gas which may be combined with CO_2-rich offgases from the enrichment column for discharge to the atmosphere. It is the enrichment step within the Rectisol process which may be viewed as pretreatment.

Enrichment of H_2S in Rectisol acid gases can also be accomplished using amine-type processes (DIPA, MDEA, or TEA). Amine processes operate by chemical absorption of acid gases. Under the proper operating conditions MDEA and TEA, and to a lesser extent DIPA, are partially selective for H_2S over CO_2, and the solutions do not appreciably absorb hydrocarbons. Thus, the major advantage of such processes in Lurgi applications is that organics which are not desirable in Claus plant feed gas are largely separated from the H_2S-rich gas. Two gaseous streams are generated: 1) an enriched H_2S stream which is sent to a Claus unit and 2) a stream containing the majority of hydrocarbons and CO_2. The CO_2-rich stream from the amine process contains residual sulfur and VOC. Decisions regarding the extent of Rectisol enrichment and necessity or desirability of amine enrichment involve both economic and technical tradeoffs in an integrated facility. From an environmental standpoint the specific enrichment process employed is not of great importance as long as the offgases are subsequently treated for sulfur control.

In addition to the flexibility for H_2S/CO_2 selectivity, the Rectisol process also provides for varying degrees of control/removal of HCN, NH_3, CO, and hydrocarbons from bulk acid gases. In Rectisol designs for Lurgi gases, the naphtha removal step also results in the removal of HCN and NH_3 since the species are very soluble in the methanol prewash solvent. About half of the removed HCN will remain as a component of the crude naphtha, the other half and essentially all of the ammonia joins the methanol/water phase. During methanol/water separation by distillation, HCN can either be stripped for routing to a Claus unit for destruction or fixed via caustic addition for subsequent treatment in the aqueous phase.

Control of carbon monoxide in acid gases can be provided by Rectisol systems. Carbon monoxide is sparingly soluble in methanol, and that which is absorbed at process pressure from Lurgi gas can be largely recovered as a separate CO-rich CO_2 stream by flashing of laden methanol to an intermediate pressure before H_2S/CO_2 removal. The CO-rich offgas can be subsequently incinerated, perhaps with heat recovery. The CO-rich offgas may also be recompressed for addition to Rectisol product gas if the resulting CO_2 load is compatible with synthesis requirements. Either approach is usually preferred to "add on" control of CO in CO_2-rich acid gases (selective mode) or H_2S lean acid gases (nonselective mode) due to the energy penalty associated with incineration of high volume, low heating value gases.

Control of potential VOC emissions can also be achieved to some extent via Rectisol design. Hydrocarbons vary in their solubility in methanol according to their molecular weight. Ethane exhibits limited solubility while propane is intermediate in solubility between H_2S and CO_2. Hydrocarbons with more than three carbon atoms (C_4+) are more soluble than H_2S in cold methanol and are largely removed in the naphtha prewash step of either selective or nonselective Rectisol. The ethane/ethylene component of Lurgi gas presents the greatest difficulty for control since C_2s constitute the largest non-methane hydrocarbon component of Lurgi gas and most C_2s will be removed from Lurgi gas by cold methanol. Only part of the absorbed C_2s can be recovered by flash regeneration; hence the remainder will be present in either the CO_2-rich offgases of selective Rectisol or H_2S-lean offgases of nonselective

Rectisol. The C_3/C_4 component can be largely recovered in the H_2S-rich offgas of selective Retisol with little remaining in the CO_2-rich fraction. Essentially all C_3/C_4s would be potential emissions in H_2S-lean offgas from non-selective Rectisol.

As mentioned previously, amine processes have the advantage of separating organics from H_2S during enrichment. Thus, amine enrichment simplifies Claus plant design compared to enrichment with selective Rectisol. However, the amine offgas containing the separated organics would also contain some sulfur compounds. In contrast, enrichment within selective Rectisol can result in a nearly sulfur-free offgas.

Amine processes using DIPA or MDEA are not expected to generate secondary wastes other than sour condensates when excess moisture must be handled in feed gases. Some solvent losses are reported due to leaks, but no routine blowdown of solvents is reported in existing applications.

Bulk Sulfur Removal

To date, only three processes have had any significant commercial application for the removal of H_2S from acid or fuel gases: the Claus, Stretford, and Giamarco-Vetrocoke (G-V) processes. These are the only processes examined in the present study because of their commercial status, reliable operation, applicability to the wide range of sulfur contents in the acid gases, and, in the cases of Claus and Stretford processes, availability of operating requirements and capital cost data. It is recognized that other processes are available or have been proposed; however, it is unlikely that processes other than Claus, Stretford, or Giamarco-Vetrocoke will be utilized in first generation coal gasification facilities in the U.S. In existing applications, Stretford units are favored economically over Claus units for feeds containing only a few percent sulfur, although Claus plants have operated successfully on feeds containing as low as 8% H_2S. The Giamarco-Vetrocoke process is generally applicable to streams with H_2S concentrations of up to 1.5%. Table 4-4 summarizes the key features of bulk sulfur removal processes.

The Claus process is a dry, high temperature process in which H_2S is catalytically reacted with SO_2 to form elemental sulfur. Two basic versions of the process: "straight through," and "split flow," are described. In the "straight through" mode sufficient air is added to oxidize one-third of the H_2S to SO_2. The "split flow" mode, shown in Figure 4-1, is often used when H_2S-levels in the feed gas are below 25% by volume or where high CO_2 levels are encountered. The acid gas is split into two streams and one-third of the input acid gas is combusted in a reaction furnace to form SO_2. Heat is recovered from the gas before it is recombined with the other two-thirds of the feed. The combined stream then enters a series of converter stages where elemental sulfur is produced. Regardless of the Claus mode, the number of stages determines sulfur removal efficiency; Claus units of three-stage design

TABLE 4-4. KEY FEATURES OF BULK SULFUR REMOVAL PROCESSES

	Claus	Stretford	Giamarco-Vetrocoke (G-V)	Incineration/SO_2 Removal
Principle of Operation	Catalytic oxidation of H_2S and SO_2 to elemental sulfur.	Liquid phase oxidation of H_2S to elemental sulfur in an alkaline solution of metavanadate and anthraquinone disulfonic acid.	Liquid phase oxidation of H_2S to elemental sulfur in sodium carbonate and arsenate/arsenite solution.	Oxidation of reduced sulfur and organics, followed by SO_2 removal using either regenerative or throwaway FGD technologies.
Components Removed	H_2S, COS, RSH, VOC, NH_3, and HCN.	H_2S, HCN, and CH_3SH.	H_2S, COS, and CS_2.	H_2S, COS, RSH, VOC, and CO.
Efficiency	Over 95% total S, other combustibles partially destroyed.	As low as 1 ppmv H_2S but no removal of non-H_2S sulfur.	99.99% H_2S removal.	As low as 100 ppmv VOC is incinerated gas and up to 99% total sulfur removal.
Feed Stream Requirements/ Restrictions	Streams containing H_2S levels much below 10% require enrichment prior to processing. Organics cause combustion control problems and "grey" sulfur.	High HCN loading should be reduced prior to processing to prevent excessive solution purge.	Maximum 1.5% H_2S in feed.	In principle, gases with any level of H_2S and other reduced sulfur compounds could be incinerated and subsequently treated via FGD. Other components cause no problems.
Byproducts	Elemental sulfur.	Elemental sulfur.	Elemental sulfur which may require arsenic removal.	Either $CaSO_4$, concentrated SO_2, or throwaway lime sludges are generated by FGD units.
Secondary Waste Streams	Spent catalyst and catalyst regeneration decommissioning offgas.	Oxidizer vent gas and purge solution.	Oxidizer vent gas and arsenate/arsenite wash water.	Some condensate and scrubber sludge.
Reliability/ Limitations	NH_3 and HCs may cause catalyst plugging and variable sulfur recovery.	Process does not remove COS, RSH, or organics. HCN forms nonregenerable salts in scrubbing solution.	Hazardous nature of arsenic solution may cause handling and safety problems.	FGDs have varying degrees of reliability and generally have lower onstream factors than process units.
Effects of High CO_2 in Feed	Can adversely affect sulfur removal ability of the process.	High CO_2 concentrations will decrease absorption efficiency by lowering solution alkalinity. Increased absorber tower height and addition of caustic are required.	Little or no effect.	No effect except to increase energy requirement for incineration if insufficient combustibles are present in feed gas.

(Continued)

TABLE 4-4. (Continued)

	Claus	Stretford	Giamarco-Vetrocoke (G-V)	Incineration/SO_2 Removal
Capital Costs[a]	\$25 to \$180 x 10^3 per Mg sulfur/day capacity depending on both total flow and sulfur content.	\$110 to \$270 x 10^3 per Mg sulfur/day capacity, depending primarily upon total flow.	No cost data available.	\$700 to \$1700 x 10^3 per Mg sulfur/day capacity depending upon total flow and degree of sulfur removal.
General Comments	Applicable only to acid gases from selective AGR. Hydrocarbon removal from feeds may be necessary.	1 ppmv H_2S in tail gas is possible, however higher limits are proposed when high levels of other reduced sulfur species are present in tail gas.	Limited data available. Hazardous nature of arsenic solution makes application unlikely in large U.S. facilities.	FGD process has usually been applied to combustion flue gases containing less than 5000 ppmv SO_2 and achieving about 90% control. Performance and cost data for higher SO_2 feeds achieving 99% control are limited.

[a] Costs are first quarter 1980 dollars.

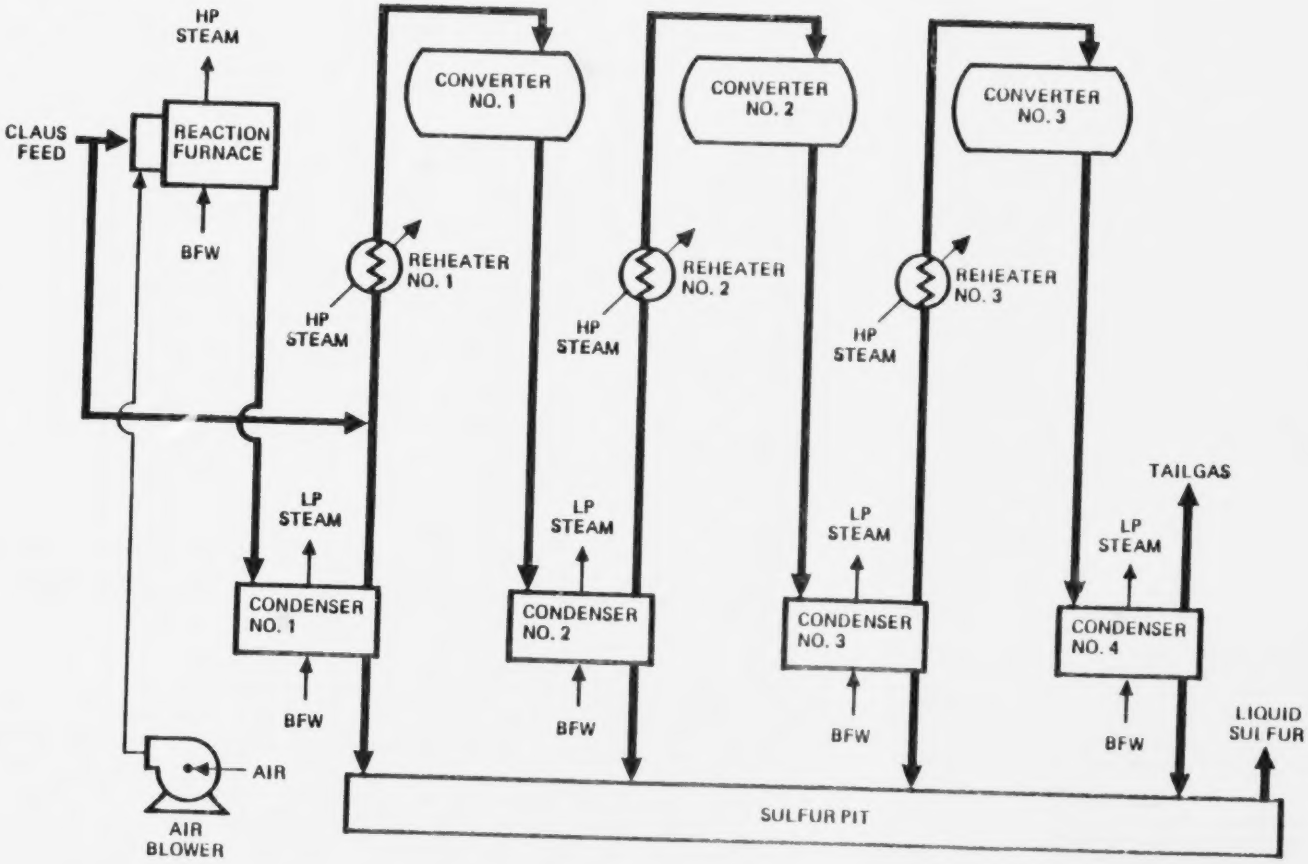

Figure 4-1. Three stage Claus plant with split flow option

can achieve overall removal efficiencies of over 95%. Gaseous sulfur species distribution in Claus tail gas in high CO_2 applications is approximately 60% H_2S, 30% SO_2, 9% COS, and 1% CS_2. Elemental sulfur as both vapor and entrained mist can contribute 20 to 50% to the total sulfur in Claus tail gases, depending primarily on the level of H_2S in the Claus feed and the effectiveness of mist eliminators. The relative contribution of elemental sulfur to total sulfur in Claus tail gas generally increases as H_2S content of Claus feed gas decreases.

In the "straight through" mode of Claus operation, organics, HCN, and NH_3 in the feed are largely converted to carbon dioxide, water vapor, and elemental nitrogen. Such components are not ordinarily of concern unless levels exceed perhaps 1% each. Organics make control of combustion stoichiometry and temperature more difficult and can lead to sulfur-containing elemental carbon (grey sulfur), particularly when olefins and aromatics are present in the Claus feed. HCN at high levels causes corrosion throughout the process while NH_3 can form deposits which plug/deactivate Claus catalysts. The problem with organics is usually solved by limiting their content in the Claus feed. HCN at high levels can be destroyed (converted to NH_3) prior to entering the Claus furnace using Claus or shift type catalysts under reducing conditions. Ammonia at high levels requires either bulk removal prior to Claus or special design to control temperatures and minimize deposition of ammonia salts.

Use of the "split flow" mode allows for control of the sulfur combustion process in the Claus plants with feeds containing less than about 25% H_2S or more than about 30% CO_2. Only about one-third of the organics, HCN, and NH_3 in Claus feed gases would be destroyed in the split flow mode unless streams containing high levels of these constituents are specifically routed to the combustion furnace of the Claus plant. Generally, organics present the most difficult problem for split flow Claus plants, leading to carbon contaminated sulfur. Two thirds or more of the input organics, HCN, and NH_3 to split flow Claus plants may be present in Claus tail gases prior to incineration.

Due to the problem of carbon contaminated sulfur with split flow operation, other approaches to combustion control with dilute Claus feeds have been utilized. First, combustible gases such as CO, H_2, or CH_4 are added to the feed in the straight through mode. Liquid sulfur has also been used. Second, and of particular attractiveness in coal gasification facilities, is the use of oxygen or enriched air. Use of O_2 not only improves flame stability but also decreases the inert volume throughout the Claus and any subsequent tail gas treatment units. Since unit sizes and associated costs are flow-dependent, savings can be realized. Of course, oxygen is expensive to generate, but much of the capital cost is already absorbed in a gasification facility which would necessarily have a large oxygen plant onsite. Thus, the incremental O_2 costs for Claus use would be relatively low. Finally, the acid gas and/or air can be preheated before being fed to the Claus burner, using steam or flue gas from fuel combustion as the heating media.

The Claus process produces spent catalyst and catalyst regeneration off-gases where catalyst regeneration has been used. The Claus catalyst has an estimated life of two to three years. Regeneration of catalyst is performed intermittently at a few facilities when the efficiency of the process drops below accepted levels.

The original Stretford process (as developed by the British Gas Corporation) is a liquid-phase oxidation process using an aqueous solution of sodium vanadate and anthraquinone disulfonic acid (ADA) in which H_2S is both absorbed and converted to sulfur. Figure 4-2 is a simplified flow diagram of the Stretford process. The H_2S is absorbed in either a packed tower (or

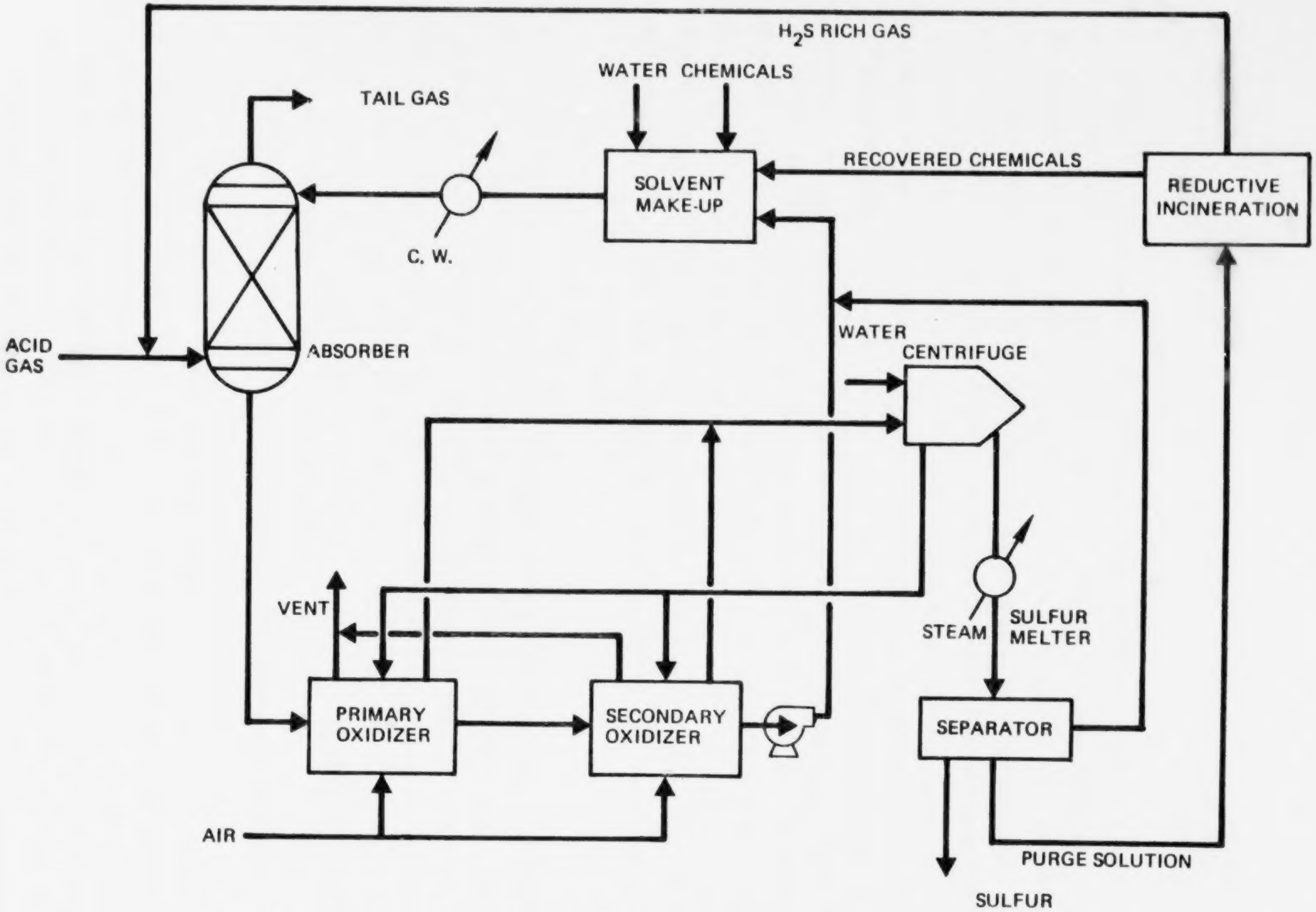

Figure 4-2. Simplified flow diagram of the Stretford process

contacted in a venturi scrubber) and then oxidized to sulfur by the sodium vanadate. Reduced vanadium is then oxidized by the ADA solution. ADA is regenerated by air in the oxidizer tanks where elemental sulfur is removed as a froth. A continuous solution purge is required to remove the buildup of sodium thiosulfate and sodium thiocyanate. Until recently, disposal or treatment of the purge solution containing thiosulfate, thiocyanates, and small amounts of vanadium salts was required. In 1973, a reductive incineration process was developed which converts the purge solution into a gas stream containing H_2S, water vapor, and a solid residue containing soda ash and reduced vanadium salts. The salts are returned to the Stretford process as makeup chemicals and the H_2S-rich gas and water vapor are recycled to the absorber as shown in the figure. Thus, the reductive incineration process recovers expensive chemicals while effectively attaining a zero discharge of purge solution. To date, no commercial Stretford unit has employed the reductive incineration process.

Recently, modifications of the original Stretford process have been developed. One version of the Stretford process has been used at the SASOL Lurgi coal gasification complex in South Africa. At SASOL, severe plugging problems have occurred in the Stretford towers which apprently relate to the high CO_2 levels in the Stretford feed compared to feeds in other applications. Preliminary information indicates that sulfur deposition is primarily responsible. SASOL has modified the original Stretford unit, presumably substituting a different absorbent but saving the bulk of the existing equipment.

The process modifications mentioned previously owe a major portion of their design/development impetus to this SASOL experience. In one, under development by Union Oil, a different (proprietary) solution is employed, while in the other (Peabody-Holmes) a venturi absorber replaces the packed tower. The latter Peabody design, which features reductive incineration of Stretford blowdown, is used as the basis for evaluation in this document.

The Stretford process generates two waste streams: the oxidizer vent gas and the purge solution. The purge solution is treated via the reductive incineration process where sulfur is recovered as H_2S for recycle to the absorber and sodium and vanadium salts are recovered for reuse. The oxidizer vent gas is expected to consist mostly of air, CO_2, and water vapor; however, some mercaptans and ammonia may also be present.

Except for the Stretford unit at SASOL, applications of the Stretford technology to date have been in natural gas, coke, petroleum, and related industries with feed gases containing only a few percent CO_2 and little, if any, non-H_2S sulfur compounds. With feed gases such as those at SASOL which contain over 90% CO_2, CO_2 absorption by the Stretford solution lowers the pH and alkalinity which in turn lowers the rate of H_2S absorption. Larger Stretford towers can be employed to address the H_2S absorption kinetics problem. Caustic addition is necessary for pH control which leads to larger solution blowdown rates. The secondary problem of sulfur formation and deposition in the absorption towers occurs when alkalinity is not maintained, and is thought to result from decomposition of thiosulfate.

A separate limitation from the operating problems which the Stretford process has experienced in the high CO_2 application at SASOL, is that the process is not capable of removing carbonyl sulfide. Whether any removal of mercaptans from feeds containing such species occurs is also unclear at this time. Very low levels of H_2S can, however, be obtained in Stretford offgases, with many units in low CO_2 applications reporting less than 10 ppmv H_2S. Unit costs, however, increase with decreased H_2S in the offgas. Designs proposed for application in several U.S. coal gasification facilities call for 100 ppmv (or less) H_2S. Since as much as 1300 ppmv of non-H_2S sulfur compounds are present in Stretford tailgases, designers apparently felt that levels of H_2S lower than 100 ppmv were not justified.

Noncondensible organic components of Stretford feed gases pass through the process essentially unchanged (unabsorbed). In contrast, HCN and NH_3 in feed gases are largely absorbed in the Stretford solution. HCN is converted to SCN^- which would eventually exit the system with the purge solution. Generally, levels of a few ppmv HCN present no problems, but higher levels translate into larger solution blowdowns. Ammonia absorbed from Stretford feed gas is partly expelled during the sulfur oxidation step by air stripping. An "inventory" of NH_3 would be established by the circulating solution so that some NH_3 would also exit the system with the blowdown. In Lurgi applications, NH_3 and HCN originate from the gas liquor stripper overhead rather than from Rectisol acid gases. Levels of these species in the overhead gases are not large enough to present problems of excessive purge solution or oxidizer emissions.

The Giamarco-Vetrocoke H_2S removal process is a liquid phase oxidation process using an absorbent solution of alkali arsenates/arsenites in which H_2S is both absorbed and converted to elemental sulfur. Sodium carbonate is the alkali usually applied for removal of large quantities of sulfur because of its relatively low cost. The Giamarco-Vetrocoke process is applicable to gas streams containing up to 1.5% H_2S and can reduce H_2S levels to 0.5 ppmv or less. The H_2S is absorbed at pressures from 0.1 to 7.5 MPa by countercurrent absorption. Rich solution from the absorber is subsequently oxidized in an atmospheric pressure, air-blown column to produce regenerated solution and elemental sulfur. Product sulfur is recovered by froth flotation, filtered, and washed. Based upon limited available data, the only waste streams generated by this process are wash water from the sulfur washing operation and oxidizer vent gas. Characterization data are not available for these streams, although the wash water will contain arsenate/arsenite absorber solution.

One other approach to bulk sulfur control should be mentioned. In principle, acid gases can be directly incinerated to convert organics, CO, and reduced sulfur and nitrogen species to CO_2, H_2O, N_2, and SO_2. SO_2 removal from the incinerated gas could then be accomplished using any one of a number of available FGD processes (see Section 4.1.2). Generally, such an approach is unattractive for several reasons. First, throwaway FGD systems create large solid waste disposal problems. Secondly, recovery type FGD systems often feature Claus or Claus type processes for elemental sulfur recovery; thus, there is little to be gained over direct use of Claus or Stretford. For example, the Allied process (licensed by Allied Chemical Corp.) is essentially a Claus unit preceded by a reduction step where part of the SO_2 is reduced to H_2S with gas containing CO/H_2. H_2S and SO_2 are then converted to elemental sulfur over a catalyst. Thirdly, in high SO_2 applications, FGD systems are expected to be several times more costly than Claus or Stretford plants applied directly to crude acid gases.

However, for facilities using very low sulfur coals, the direct incineration/FGD approach might be employed. For coals with, for example, less than 0.2% sulfur, nonselective Rectisol acid gases would contain less than 0.3% H_2S. Enrichment of such low sulfur gases to levels suitable for Claus processing or direct application of Stretford may not be as economically attractive as the incineration/FGD alternative, particularly if the FGD system could be integrated with the onsite boiler.

Tail Gas Treatment - Residual Sulfur

A number of processes are commercially available for treatment of sulfur plant tail gases or other waste gases containing low levels of reduced sulfur species. Table 4-5 summarizes the key features of the most prominent of these processes. The processes can be broken down into three generic types:

1) Extensions of the Claus process - such as IFP-Clauspol 1500, Sulfreen, and BSR/Selectox.
2) Conversion of sulfur species to sulfur dioxide (SO_2) by incineration, followed by SO_2 removal - such as Wellman-Lord or Chiyoda Thoroughbred 102.
3) Conversion of sulfur species to H_2S followed by its removal using such processes as Beavon/Stretford and SCOT.

Processes in the first category are used exclusively for Claus plant tail gases and are capable of approximately 80% recovery of the sulfur in the tail gas. These extensions of the Claus process require a 2:1 H_2S to SO_2 ratio for proper operation. These processes have limited removal capabilities (not less than 1000 ppmv total sulfur) and have not been proposed for application in Lurgi gasification facilities in the U.S.

The second category of processes involves incineration of the waste gas followed by SO_2 removal. Such processes are capable of achieving levels as low as 150 ppmv of SO_2 in tail gas. One of the more prominent processes, the Wellman-Lord, was examined for costing purposes. The Wellman-Lord process removes SO_2 with an alkaline sodium sulfite solution. Subsequent regeneration of the absorbent generates a concentrated SO_2 stream which would be recycled to the parent Claus plant. Two approaches to incineration can be employed,

TABLE 4-5. KEY FEATURES OF RESIDUAL SULFUR REMOVAL PROCESSES

	Beavon	SCOT	Incineration	Incineration Plus SO_2 Removal (FGD)
Principle of Operation	Catalytic reduction of sulfur compounds to H_2S, followed by integrated Stretford process.	Sulfur species are catalytically reduced to H_2S; H_2S is scrubbed in a regenerable amine system.	Thermal incineration in incinerator or onsite steam and power boiler or catalytic incineration.	Incineration (on onsite boiler or separate incinerator) followed by SO_2 removal (e.g., Wellman-Lord).
Components Removed	H_2S, COS, C_2, and SO_2.	H_2S, SO_2, COS, and CS_2.	Converts reduced sulfur species to SO_2, also removes HCs, CH_3SH, NH_3, and HCN.	SO_2, also removes HCs, CH_3SH, NH_3, ad HCN.
Efficiency	Up to 99.8% total sulfur removal in combination with the Claus plant or can attain equivalent of 50 ppm total sulfur in tail gas (not including reducing gases).	Up to 99.5% total sulfur removal in combination with the Claus plant or can attain equivalent of 250 ppm total sulfur in tail gas (will vary depending on CO_2 and H_2S concentration in specific applications).	Essentially 100% conversion of reduced sulfur to SO_2. No removal achieved.	Up to 99% total sulfur removal from Claus tail gas or 50 ppm SO_2 in tail gas and complete removal of other compounds.
Feed Stream Requirements/ Restrictions				
Byproducts	Elemental sulfur.	Concentrated H_2S.	None.	Sulfur or sulfuric acid from Wellman-Lord process.
Secondary Waste Streams	Sour condensate, oxidizer vent gas, solution purge and spent catalyst.	Sour condensate and spent catalyst.	Spent catalyst from catalytic incineration.	Sour condensate and solution purge.
Reliability/ Limitations	Has only been applied to Claus process tail gases.	Requires further treatment and/or recycle to Claus.	Does not remove sulfur; only converts to another form (SO_2). Catalytic incineration may not be able to handle high-HC and sulfur content gas streams.	Solid wastes may be generated by throwaway FGD processes.
Effects of High CO_2 in Feed	Reduces conversion efficiency of catalyst and decreases H_2S absorption in Stretford solution.	Reduces conversion efficiency of catalyst and efficiency of alkanolamine system.	None.	None.
Capital Costs[a]	$20 to $60 x 10^6 per Mg/day of S at Claus plant.	$20 to $60 x 10^6 per Mg/day of S at Claus plant.	Refer to Table 4-3 for costs.	$40 to $110 x 10^6 per Mg/day of S at Claus plant.
General Comments	Exact ppm limit achievable in coal gasification application is not known. 100 ppm is believed by vendor to be attainable.	Offgas from amine scrubber is not as low in total sulfur as Beavon process.	May be a low cost control for streams with small amounts of sulfur compounds. Onsite boiler incineration can simultaneously remove SO_2 in FGD.	Onsite boiler/FGD system is the most likely candidate. Installing a separate incinerator and FGD would not be as economically feasible.

(Continued)

TABLE 4-5. (Continued)

	Sulfreen	Cleanair	IFP Claus 1,500	IFP-2	BSP/Selectox
Principle of Operation	Solid phase continuation of Claus reaction at a low temperature.	Catalytic reduction of sulfur compounds to H_2S followed by a continuation of the Claus reaction and Streford process.	Liquid phase continuation of Claus reaction at a low temperature.	Incineration of tail gas followed by ammonia scrubbing. Solution is evaporated to produce a concentrated SO_2 stream which is returned to the Claus plant.	Catalytic reduction of sulfur compounds to H_2S, followed by oxidation of H_2S to sulfur over Selextox catalyst.
Components Removed	H_2S, SO_2, COS, and CS_2.	H_2S, COS, CS_2, and SO_2.	H_2S and SO_2.	COS, CS_2, and H_2S.	H_2S, SO_2, COS, and CS_2.
Efficiency	Up to 30 to 35% removal of sulfur in the tail gas.	Reduces sulfur to less than 250 to 300 ppm SO_2 equivalent in effluent.	Reduces sulfur species in Claus tail gas to 1500 ppm as SO_2.	Reduces sulfur species in Claus tail gas to less than 500 ppm.	Up to 99.5% total sulfur removal equivalent to 750 ppmv SO_2 in the incinerated offgas.
Feed Stream Requirements/ Restrictions	Optimum performance requires $H_2S:SO_2$ ratio of 2:1.	$H_2S:SO_2$ ratio can vary up to 8:1 without affecting efficiency; designed specifically for Claus tail gas.	$H_2S:SO_2$ ratio must be maintained in the range of 2:0 to 2:4.	$H_2S:SO_2$ ratio must be maintained in the range of 2:0 to 2:4.	$H_2S:SO_2$ ratio must be maintained in range of 2:0 to 2:4. HC and NH_3 should be in the feed.
Byproducts	Elemental liquid sulfur.	Elemental sulfur.	Elemental sulfur.		Elemental liquid sulfur.
Secondary Waste Sreams	Spent catalyst.	Spent catalyst.	Spent catalyst.	Spent catalyst.	Spent Beavon and Selectox catalyst, and sour condensate.
Reliability/ Limitations	Has only been applied to Claus process tail gases.	Has only been applied to Claus process tail gases.	Has only been applied to Claus process tail gases.	Has only been applied to Claus process tail gases.	Has only been applied to Claus plant tail gas.
Effects on High CO_2 in Feed	No effect.	Reduces conversion efficiency of catalyst; decreases H_2S absorption in Stretford solution.	No effect.	No effect.	Reduces conversion efficiency of BSR catalyst.
General Comments	Much higher residuals in tail gas than Beavon process.	Cannot attain as low a residual sulfur level in tail gas as Beavon process.	Cannot attain as low a residual sulfur level in tail gas as Beavon process.	Cannot attain as low a residual sulfur level in tail gas as Beavon process.	Higher sulfur emissions than Beavon process.

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[a] Costs are first quarter 1980 dollars.

either separate incineration (with added fuel where needed) or incineration in an onsite boiler. Either option would produce similar net results from the standpoint of sulfur oxidation.

The third category of processes involves catalytic reduction of oxidized sulfur species to H_2S followed by H_2S removal from the gas stream by solvent absorption. In general, the designs of these processes are influenced by high levels of CO_2 in the feed gas. The CO_2 reduces the efficiency of catalytic reduction of COS and CS_2 to H_2S and impairs the effectiveness of the H_2S removal/recovery systems.

Both the Beavon/Stretford and SCOT processes are commercially available catalytic processes which are potentially applicable to coal-derived sulfur plant tail gases. These processes feature two sections: a hydrogenation section to convert sulfur species in the gas to H_2S and an H_2S absorption section. In the hydrogenation reactor a reducing gas is added to the feed gas and the combined gas stream is passed over a cobalt molybdate catalyst. The hydrogenation/hydrolysis reactions occur in the catalyst bed reducing the sulfur species to H_2S. From the standpoint of non-H_2S conversion, the Beavon and SCOT catalytic steps may be considered as nearly equivalent.

The Beavon process includes a Stretford unit for H_2S absorption. The SCOT process includes absorption of the H_2S in an alkanolamine scrubbing system. The absorbing solution is then regenerated, resulting in a H_2S-rich acid gas which is ordinarily returned to the parent Claus plant for treatment. The alkanolamine scrubbing system ultimately limits the SCOT's capabilitities because the solvent is only partially selective for CO_2 over H_2S. Thus, where feeds contain large amounts of CO_2, it is more difficult to generate an H_2S stream suitable for Claus processing while simultaneously obtaining a tail gas stream with a low level of total sulfur. In high CO_2 applications, vendors of the Beavon process report that levels of less than 100 ppmv total sulfur can be achieved, while vendors of the SCOT process guarantee less than 350 ppmv total sulfur (Claus plant tail gas bases).

Inherent limitations of selectivity in the amine absorption step of the SCOT process places a lower limit of about 200 ppmv of H_2S which will be present in SCOT tail gases. In comparison, the Stretford unit following the Beavon reactor can remove H_2S to as low as 10 ppmv H_2S. Both systems would result in 20 to 100 ppmv tail gas COS in high CO_2 applications. It might be noted that the higher levels of H_2S in SCOT tail gases in existing applications have necessitated that the gases be incinerated to minimize odor problems while Beavon tail gases have generally not required incineration. However, the previous discussion relating to the operating problems with Stretford in high CO_2 service is equally applicable to Beavon/Stretford. Also, no Beavon/Stretford units currently exist in high CO_2 service, while several SCOT units have successfully operated on feeds with CO_2 levels above 40%. These SCOT units are designed to meet a 500 ppmv total sulfur limit.

Tail Gas Treatment - VOC, CO, HCN, and NH_3

As discussed previously, partial or total control of the subject species can be achieved during bulk sulfur removal or sulfur tail gas treatment. The combustion furnace of a Claus unit destroys these constituents but only in that portion of the gas passing through the furnace. HCN can also be destroyed over Claus type catalysts used ahead of the Claus plant itself. HCN is removed from feed gases in the Stretford process, forming SCN^- which leaves the systems with the aqueous blowdown. NH_3 is also partially removed by Stretford solvent, while organics and CO are not removed by Stretford.

Catalytic sulfur tail gas treatement systems achieve control of any HCN contained in sulfur plant tail gases. Both Beavon and SCOT catalytic sections will result in essentially complete conversion of HCN to NH_3 and CO. Hydrocarbons, CO, and NH_3 contained in the feed to Beavon or SCOT units or added/generated within such units will be present in tail gases. Incineration of these tail gases would destroy these constituents. As mentioned above, SCOT tail gases are ordinarily incinerated to minimize odor problems arising from residual H_2S. Beavon tail gases (with lower H_2S levels) are not ordinarily incinerated, but an incineration step can be added for control of organics, CO, and/or NH_3. SO_2 tail gas treatment processes, such as the Wellman-Lord, inherently achieve control of VOC, CO, and NH_3 as part of the incineration step.

Table 4-6 summarizes the advantages and disadvantages of the various incineration technologies aimed primarily at control of volatile organic compounds. Generally, a greater degree of control is obtained with high temperature incineration in either a fuel-fired boiler or a separate incinerator (either thermal or catalytic) than can be achieved through the use of flares. The main combustion zone of a gas incinerator is engineered such that the

TABLE 4-6. KEY FEATURES OF INCINERATION PROCESSES

Type of Incineration	Advantage	Disadvantage	Costs (Total Depreciable Capital)[a]
Thermal Incineration via Separate Incinerator	Can handle all types of waste gases. Reliable and simple operation is common. VOC/CO control and oxidation of sulfur compounds simultaneously.	High supplemental fuel costs for streams with low heating value. Control is a problem with streams of varying flow and composition.	On basis of kmols/hr of flow: flow range of 0.3 to 3.0×10^4 kmol/hr a. no heat recovery: \$140 to \$870 b. primary heat recovery: \$190 to \$1000 c. primary and secondary heat recovery: \$225 to \$1200.
Thermal Incineration in Fuel-Fired Boiler	Sulfur and particulates can be removed in the associated electrostatic precipitator and flue gas desulfurization (FGD) units when these are integral with the boiler. The fuel required for steam boiler incineration is less than that of a separate incinerator for wastes with low heating values.	In most cases, this option is more capital intensive than a separate incinerator; however, extent of heat recovery is generally greater with boilers than with incinerators. Subject to control problems with varying waste gas flow rates and compositions.	Incremental boiler capital costs are \$2000–\$3000/kg mole of incremental flue gas compared to coal combustion on a heating value basis. Incremental ESP and FGD costs are an additional \$2000–\$2500/kg mole incremental flue gas.
Catalytic Incineration	Requires less fuel than thermal incineration, although heat recovery may not be as high. Waste gases with very little combustible material can often be incinerated catalytically without supplemental fuel.	Cannot handle large quantities of particulates; they will gradually coat the catalyst and reduce its efficiency. Some catalyst can be easily poisoned by sulfur compounds and elements such as arsenic and lead. High levels of hydrocarbons can raise catalyst to excessive temperatures and shorten the useful life of the catalyst. Temperature control is also a problem with streams of varying flow and composition.	\$400 to \$2200 per kmol/hr of flow for a flow rate range of 40 to 7100 kmol/hr.
Flaring	Simple to operate. Least expensive alternative, especially for transient and small volume waste gases.	Destruction efficiencies believed lower than for thermal or catalytic incineration. Performance data are generally lacking.	40 to 100 ft elevated flares for flow rate range of 800 to 6500 kmol/hr – \$25 to \$125 per kmol/hr Ground flares for flow rate of 100 to 1000 kmols/hr – \$800 to \$2700 per kmol/hr.

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[a] Costs are first quarter 1980 dollars.

gases are maintained at a designed minimum temperature and residence time. Typical design values are 1090 K and 0.5 seconds. This results in nearly complete destruction of volatile organic compounds, organic aerosols, and particulate matter which contains combustible material.

Thermal incineration may also be affected in a boiler where a minimum combustion temperature of 1500 K and a minimum resident time of 0.5 second are typical design parameters. This approach results in a similar degree of pollutant destruction as in a specially-engineered incinerator. The boiler as an incinerator of waste gases necessitates a corresponding increase in the capital and annualized operating costs of captive ESP and FGD units, since the costs of the pollution control units are flow rate dependent (even if the increased gas flow to the ESP/FGD unit contains no dust or sulfur dioxide).

Catalytic incineration is not likely to be an attractive alternative for VOC and CO control of tail gases from sulfur recovery units due to the presence of sufficient reduced sulfur compounds to interfere with or degrade catalysts. However, catalytic incineration of CO-rich flash gases from Rectisol has considerable promise and is featured in the recent design of at least one U.S. coal gasification facility under construction (based on Texaco gasification).

4.1.1.1 H_2S-Rich Acid Gases

H_2S-rich acid gases are sulfur-containing Rectisol gases which have purposely been enriched either as part of acid gas removal or by use of additional processing so that Claus sulfur recovery may be used. It was assumed that a minimum of 10% H_2S is necessary for proper operation of the Claus process. Rectisol units in the subject facilities remove from 5500 to 6600 kmols/hour of acid gases from quenched Lurgi gas. Generally, higher rank coals produce slightly more acid gases (CO_2 plus H_2S) in Lurgi gasification than lower rank coals. H_2S, COS, and mercaptans in these acid gases amount to 80 to 200 kmols/hour (60 to 140 Mg/day) depending on the feed and sulfur content. H_2S-rich acid gases containing 10 to 30% H_2S would represent 5 to 30% of the total acid gas volume, or 300 to 2000 kmols total per hour.

The exact H_2S levels in the design values for Claus feeds would be determined by engineering/economic tradeoff studies of enrichment costs vs. Claus and tail gas treatment costs and would vary for coals with different sulfur contents. Similarly, use of split flow vs. straight through mode and use of pure oxygen vs. air would also involve tradeoff studies. From an environmental performance standpoint, these design variations are essentially equivalent. Capital costs for the Claus plant range from \$4 to \$12 million depending primarily upon the volumetric flow and, to a lesser extent, the sulfur loading. This large range largely reflects costs either incurred or avoided upstream in enrichment. For an example, a Claus plant processing 180 kmols/hr of 40% H_2S feed gas has an estimated capital cost of \$7 million.

Depending upon the Claus feed H_2S level, overall sulfur recovery may vary from as low as 90% to over 95%. Less concentrated feeds result in lower percentage recoveries. Organics, CO, and reduced nitrogen species will be almost completely destroyed in straight through Claus units and partially destroyed in split flow units.

The only secondary waste stream generated by all Claus units is spent catalyst. The subject Claus plants would have bauxite or alumina catalyst inventories ranging up to approximately 100 Mg which would require disposal every few years. Claus catalyst regeneration occurs infrequently at a few facilities, and thus was not evaluated in this document.

4.1.1.2 H_2S-Lean Acid Gas

These gases refer to acid gases containing more than 500 ppmv but less than 10% total sulfur and include 1) Claus tail gases, 2) amine enrichment offgases, and 3) nonselective Rectisol acid gases. Also included in this category is the oxidizer vent gas (a secondary waste stream) from the Stretford process.

Claus Tail Gases

In the subject facilities these tail gases contain 0.3 to over 1 percent total sulfur and amount to 300 to 3000 kmols total per hour. SCOT, Beavon/Stretford, and Wellman-Lord technologies are all applicable to these gases and achieve residual sulfur levels of less than 350 ppmv total sulfur (on a Claus tail gas basis). Capital costs for these processes range from $6 to $20 million, depending primarily on the flow and, to a much lesser extent, the sulfur load. Since the relative importance of sulfur mass load vs. volumetric flow rate is somewhat different for Claus plants and tail gas treatment units, the relative costs of the Claus plant and its tail gas treatment unit will vary with coal sulfur and overall plant design. SCOT, Beavon/Stretford, and Wellman-Lord units handling the tail gas from a 140 Mg/day (40% H_2S feed) Claus plant are estimated to have capital costs of $5, $6, and $10 million, respectively. Incinerators for SCOT or Beavon tail gases have capital costs of about $1 million, or about 10% of the capital cost of the SCOT or Beavon units. In Lurgi facilities the tail gases have sufficient VOC, CO, and H_2 levels such that no supplemental fuel is needed and hence, operating costs are very low for incineration.

Secondary waste streams from the Beavon/Stretford process are 1) sour reactor effluent condensate; 2) Stretford solution purge; 3) Stretford oxidizer vent gas; and 4) spent catalyst from the Beavon reactor. Sour condensate is expected to contain dissolved sulfide and traces of NH_3, and would be generated at a rate of up to 3 m^3/hr. Stretford solution purge for control of thiosulfate and thiocyanate buildup may be present as a waste stream containing vanadium and sodium salts as thiosulfate, sulfate, carbonate, and thiocyanate. The solution purge rate is approximately 0.1 Mg/hr and purge solution may either be regenerated or discarded (refer to Section 4.1.1). Oxidizer vent gas would consist primarily of air, water vapor, and CO_2 but may contain traces of NH_3. Insufficient data are available for estimating the flow rate of oxidizer vent gas. The cobalt molybdate hydrogenation catalyst inventory is approximately 11 Mg and would require replacement about every five years.

Secondary waste streams from the SCOT process are sour water and spent catalyst. The sour water is expected to contain dissolved sulfide and NH_3, and would be generated at a rate of 4 m^3/hr. The cobalt molybdate hydrogenation catalyst inventory is approximately 11 Mg, and would require replacement about every five years.

Secondary waste streams from the Wellman-Lord process are acidic wastewater from combustion gas quenching and thiosulfate/sulfate byproduct purge. The acidic wastewater typically has a pH value between 1 and 2 and would be generated at a rate of 3 m^3/hr. Byproduct purge consists primarily of sodium salts as sulfite, pyrosulfite, sulfate, and thiosulfate with approximately 29 percent water. Byproduct purge is generated at a rate of 80 kg/hr.

Amine Enrichment Offgases

When amine processes are used to both remove organics from, and increase the H_2S content of, Claus feed, a hydrocarbon-rich offgas at least as large in volume as the Claus feed is also generated. For example, an amine unit processing 2300 kg-moles/hr of 8.7% H_2S feed gas produces 1900 kg-moles/hr of offgas containing about 2.9% nonmethane hydrocarbons, and 0.15 to 1.3% sulfur compounds. Since only about half or less of the sulfur is H_2S, catalytic or oxidative tail gas treatment processes would be most applicable. SCOT, Beavon/Stretford, and Wellman-Lord units treating the example amine offgas alone would incur estimated capital costs of $9, $10, and $17 million, respectively. However, separate tail gas treatment units would, in most cases, not be used for the subject gases since treatment of Claus tail gases would also be necessary and combined treatment would result in cost savings. Due to the organics in amine offgases, catalytic sulfur tail gas treatment offgases would probably be incinerated. Incremental incinerator capital costs for Beavon/Stretford and SCOT are estimated to be no more than 10%. Amine offgases contain sufficient VOC so that no supplemental fuel is needed for incineration.

With regard to secondary waste streams from tail gas treatment processes such as Beavon/Stretford, SCOT, and Wellman-Lord, combining the amine enrichment offgas with Claus tail gas results in increased waste generation rates. Combining the example amine enrichment offgas with the example Claus tail gas given above would result in a slight increase in sour condensate production, and a factor of two to three increase in all other secondary wastes associated with tail gas treatment.

Nonselective Rectisol Acid Gases

These gases amount to 5300 to 7200 kmols/hr in the subject facilities and contain from 1.2 to 3% sulfur compounds and about 1% nonmethane hydrocarbons. Stretford technology has been most widely proposed for treating such gases. Like the Claus tail gas treatment process, Stretford plant costs are primarily determined by volumetric flow and, to a lesser extent, sulfur mass loading.

Capital costs for a 6600 kmols/hr plant are estimated at $15 million. Stretford tail gas contains less than 1 kmol/hr of H_2S but may contain over 8 kmol/hr of COS and mercaptans and 50 kmols/hr of VOC.

Stretford tail gases have an energy value (LHV) of about 10 kcal/kmol. The adiabatic flame temperature of such a gas burned with 20% excess air is only about 900 K. Since at least 1100 K is usually required for complete destruction of organics with thermal incineration, supplemental fuel will be needed. The costs of incineration for this low heating value stream are primarily capital in nature, since heat recovery can more than offset supplemental fuel requirements (the primary operating cost item). The capital investment for an incinerator handling 6600 kmols/hr Stretford gas is $2.3 million. About 80 x 85 GJ/hr of supplemental fuel is needed, but about the same amount of medium pressure steam is generated in a typical incinerator with 35% heat recovery.

Secondary waste streams from the Stretford process are solution purge and oxidizer vent gas. Stretford solution purge may be present as a waste stream or may be regenerated for reuse (refer to Section 4.1.1). The solution purge would be generated at a rate of approximately 1 Mg/hr and contains vanadates and sodium salts of thiosulfate, sulfate, carbonate, and thiocyanate. Oxidizer vent gas consisting primarily of air, carbon dioxide, and water vapor with traces of mercaptans would be generated at a rate of approximately 1000 to 2000 kmols/hr.

Since the Stretford process does not remove non-H_2S sulfur, it might appear that using those processes designed primarily for Claus plant tail gases could be applied directly to nonselective Rectisol acid gases. In the case of the catalytic processes (SCOT and Beavon/Stretford), few, if any, advantages are seen with this approach. The high H_2S loading relative to COS would work directly against COS destruction over the catalyst in both processes (indeed COS may be actually generated in such applications). In the SCOT case the high CO_2 loading of the feed and lack of a Claus plant to which the H_2S fraction can be recycled are fundamental limitations.

Wellman-Lord could in principle be applied directly to the subject acid gases after incineration. As discussed in Section 4.1.1.1, however, direct use of FGD type processes is generally not cost effective relative to Stretford except where very low sulfur gases (e.g., very low sulfur coals) are encountered.

Stretford Oxidizer Vent Gases

During regeneration of Stretford solution, air is used as an oxidant to promote flotation of elemental sulfur. About 1000 kmols/hr of air depleted in oxygen is emitted from the Stretford oxidizer. There is some concern that mercaptans and ammonia removed from the feed gas in the Stretford absorber may be emitted in the oxidizer. Even small amounts could present an odor problem.

Controls for oxidizer vent gas are limited to direct incineration and carbon adsorption with incineration of regenerant gases. Since the vent gas contains oxygen, it can be used in place of air in an incinerator or boiler (displacing ordinary air). Due to the lower level of oxygen in the vent gas relative to air, more inerts are carried through combustion and heat recovery. Thus, an energy penalty is incurred which corresponds to heating of the extra inerts (compared to air) from the oxidizer temperature to the final combustion flue gas temperature after heat recovery. About 66% additional inerts are present in the vent gas in comparison to air.

Activated carbon adsorption for control of H_2S and mercaptans usually includes metal impregnation of carbon to enhance sulfur removal. Oxidizer gases would be discharged through a carbon bed at 280 to 310 K. After saturation, the bed is regenerated with steam, and the regeneration gases incinerated with supplemental fuel. Beds would operate in parallel so that regeneration and adsorption would occur concurrently. Since gas must be relatively dry for proper carbon performance (to prevent moisture condensation in the bed), the dew point of the gas must be lowered to about 280 K. Several approaches could be taken to remove moisture, but direct refrigeration is most likely, generating a condensate. Dewatered gas would be heat exchanged with feed gas to warm it well above the 280 K dew point.

Table 4-7 presents estimated costs for the above controls. The calculations suggest that incineration may be more costly than carbon adsorption. However, ammonia may not be controlled by the carbon approach.

TABLE 4-7. COSTS FOR CONTROL OF STRETFORD OXIDIZER VENT GASES[a]

	Incineration[b]	Carbon Adsorption
Total Capital	2.21	0.64
Total Annual Operating	0.10	0.15
Total Annualized	0.48	0.26
Percent of Base Plant Costs		
Capital	0.27	0.08
Total Annualized	0.24	0.13

[a] Costs are million of first quarter 1980 dollars.
[b] Vent gas would substitute in part for combustion air in a boiler or gas incinerator.

4.1.1.3 CO_2-Rich Acid Gases

These gases refer to the offgases from selective Rectisol containing the bulk of the CO_2 removed from Lurgi gas. The selective Rectisol at Kosovo, Yugoslavia which serves as the basis for analysis in this manual is not designed nor operated to minimize sulfur species in the CO_2 fraction. As discussed previously, however, levels of total sulfur can be as low as 10 ppmv in the Rectisol CO_2 fraction. Since most available "add on" control cannot generally achieve levels below 10 ppmv, no further sulfur control is considered for this stream type.

The CO_2 fraction may also contain about 1.5% nonmethane hydrocarbons (mostly ethane and methanol) and 0.1% CO. If VOC and/or CO control is desired, some flexibility exists in Rectisol designs for reducing the levels in the bulk CO_2 offgas. Incineration is a technically feasible "add-on" control, but the large fuel penalty associated with this approach makes its use very unlikely for such a large volume waste gas. However, incineration is feasible for a smaller volume stream(s) enriched in CO and/or VOC generated within the Rectisol process to minimize levels in the bulk CO_2 offgas. Costs associated with such "in process" control cannot readily be estimated. Also, costs for incineration of a smaller volume VOC/CO enriched gas are difficult to define since the volume of such a gas is not known.

4.1.2 Small Volume and Intermittent/Transient Waste Gases Containing VOC and Reduced Sulfur Compounds

In addition to Rectisol acid gases, several other waste streams in the subject facilities contain reduced sulfur and nitrogen compounds, organics, and CO. In principle, the same techniques discussed previously for acid gases can be applied to these streams. Indeed, combined treatment of small volume waste gases with Rectisol acid gases can offer certain technical and economic advantages. However, unlike the case with acid gases, sulfur removal is not necessarily the only or primary concern. Further, small volume and intermittent streams do not necessarily lend themselves well to control approaches designed for large volume, continuous streams.

Controls for these small volume and intermittent waste gases fall into three broad categories: 1) recovery of energy value of contained organics, CO, and H_2 via recycle to the main process train or via use as fuel; 2) incineration with or without subsequent removal of SO_2; and 3) removal of sulfur, nitrogen, or organic species, perhaps in conjunction with acid gases. Sulfur removal and incineration (including use as fuel) have been discussed previously in Section 4.1.1. Since it is probably not economically attractive to provide captive SO_2 control for the subject types of waste gases, any SO_2 control would employ larger SO_2 removal systems associated with onsite boilers/heaters. Boiler FGD systems are discussed in Section 4.1.4.

4.1.2.1 Coal Lockhopper Gases

Depressurization of the coal lockhopper, which is carried out in two stages, is a source of potential pollutants. When using Lurgi gas as the pressurant for the coal lockhopper, the internal pressure of the lockhopper during the first-stage depressurization is reduced from approximately 3.1 MPa to about 0.11 MPa, based on current operating practices at the SASOL facility in South Africa as well as the design criteria for a Lurgi plant proposed for the United States. The pressure is then further reduced to atmospheric during the second-stage depressurization using an air ejector system. Therefore, for the purposes of this document, high-pressure lockhopper gases are defined as those gases discharged from the coal lockhopper with a pressure of over 0.11 MPa when using product gas as the pressurant. Below 0.11 MPa these discharges are defined as low-pressure lockhopper gases. In some instances, inert gas rather than Lurgi gas has been proposed as the pressurant because of environmental emissions limitations imposed by regulatory agencies (e.g., New Mexico State Health Department).

Control alternatives for the high-pressure lockhopper gas stream include recompression and recycle of the gas stream to the quenched gas stream or use as fuel in the boiler or incinerator, with or without particulate matter and SO_2 control. Recompression and recycle would result in no emissions to the atmosphere, while incineration of the lockhopper gas stream would result in a net increase in emissions of particulate matter, SO_2, and NO_x. Costs and energy requirements for the control alternatives for the high-pressure coal lockhopper gas stream are anticipated to be offset by the savings resulting from the recovered heat or synthesis components.

Of major concern with the low-pressure coal lockhopper gas is polycyclic organic matter (POM), and hence the control alternatives are aimed primarily at particulate matter/organic aerosol control. Accordingly, control alternatives for the low-pressure coal lockhooper vent gas stream consist of 1) boiler, 2) thermal incinerator, 3) flare, 4) venturi scrubber, and 5) vent gas dispersion. The first three alternatives involve incineration in some manner. When the boiler is used as an incinerator for such waste gases, the gas would be substituted for secondary air. In this case, no oversizing of the boiler or its captive ESP or FGD systems is necessary. However, provisions for collecting and holding of the gas and delivery to the boiler are required. No energy penalty need be incurred in the boiler case since the heating value of the waste gas is largely recovered in modern boiler systems. The boiler alternative also results in the control of reduced sulfur compounds present in the lockhopper gas. When a captive incinerator is used, provisions would again be required for delivery and storage, although piping distances and holding volumes would be lower than in the boiler case. An energy penalty would probably be incurred with an incinerator, since the extent of heat recovery practical with small incinerators is not as high as with large boilers. Flare systems would be even simpler than incinerators or boiler use, requiring no gas holding. With flares, complete combustion cannot be assured at all times and of course there is no energy recovery.

Incineration of lockhopper gases may involve safety risks. The SASOL Lurgi facility coal lock design featured a common header for 10 gasifiers and a blower exhaust to collect the low pressure lockhopper gases. This system was abandoned because of explosion hazards which were encountered. Several modifications to the SASOL design have been examined, including dilution of the gas using the air ejector system to maintain the gas mixture well below the lower explosive limit and use of flashback controls in the ducting system. Even with such measures, there is always some risk in piping gases containing air, combustible gases, and coal dust.

The alternative to air ejection of residual lockhopper gases is the use of inert gas. Either N_2 from the air separation plant or CO_2 from Rectisol or methanation units could be used for this purpose. Any diluent gas (other than air) would incur energy penalties in subsequent incineration/heat recovery units as well as increased capital costs for gas collection and transport. Inert gas ejection could be coupled with venturi scrubbing as a control alternative since particulate matter is the primary concern with this stream. Only a small collection system and fan would be needed along with the scrubbers.

A final approach, aimed only at dispersing the low-pressure lockhopper gas, involves ejection with air and subsequent dilution with additional heated air to aid in thermal buoyancy. The diluted gases are emitted through a stack to minimize ground levels of pollutants.

Table 4-8 summarizes the costs of controls for lockhopper gases. Costs for compression and recycle are not estimated due to the design specific nature of such costs. The high-pressure lockhopper gas is a valuable fuel, but it produces a greater volume of flue gas than does coal on a heating value basis. Thus, all boiler heat exchange components would need to be oversized accordingly. In Table 4-8 both boiler and ESP/FGD costs have been derived by oversizing base plant units by 12% to account for this increased flue gas volume. Since increased flue gas volume at constant heat input also translates into lower efficiency in heat recovery, a small downrating (about 1%) of the boiler is also necessary with high-pressure lockhopper gas.

High-pressure lockhopper gas has sufficient heating value that incineration costs at the boiler are more than offset by recovered energy, even when the boiler has a captive ESP/FGD system. Such is not the case with low pressure lockhopper gas diluted with air where collection and transport costs dominate. The increased flue gas volume and boiler downrating discussed above

TABLE 4-8. COSTS ASSOCIATED WITH CONTROL OF LOCKHOPPER VENT GASES

Control Technique	Estimated Control Costs[a]				
	Total Capital	Total Annual Operating[b]	Total Annualized[b]	Percent of Base Plant Costs	
				Capital	Total Annualized[b]
Incineration in Boiler					
HP Gas	2.01	(3.35)	(3.0)	0.25	Negative
LP Gas[c]	0.29	(0.05)	0.02	0.04	0.01
Boiler Plus ESP/FGD					
HP Gas	3.14	(3.18)	(0.02)	0.38	Negative
LP Gas[c]	0.31	(0.04)	0.01	0.04	<0.01
Inert Gas Ejection Plus Incineration Without Heat Recovery					
LP Gas	0.28	0.02	0.07	0.03	0.04
Inert Gas Ejection Plus Flare					
LP Gas	0.09	0.01	0.02	0.01	0.01
Inert Gas Ejection Plus Venturi Scrubber					
LP Gas	0.09	0.01	0.03	0.01	0.01
Hot Air Dispersion					
LP Gas	0.20	0.05	0.09	0.02	0.04

[a] Costs are millions of first quarter 1980 dollars.
[b] Air ejection.
[c] Values in parenthesis indicate negative costs due to energy credits.

with high-pressure lockhopper gas would also apply to the low-pressure lockhopper gas. However, the residual lockhopper gas is diluted with air for safety purposes, and it is this air which is substituting for air needed at the boiler for fuel combustion. Hence, only a very small change in boiler size is required to accommodate the lockhopper gas, and this is ignored in the Table 4-8 calculations. In different words, the boiler air feed system continually draws air from the lockhopper vent header system, and the contained residual gasifier components are swept along in the process.

Low-pressure lockhopper gas diluted with inert gas and handled by thermal incineration, venturi scrubbing, and flaring incurs progressively lower costs with each option. Hot air dispersion is the least costly alternative, but achieves no removal or destruction of pollutants.

The degrees of emission control associated with the control alternatives in Table 4-8 are difficult to estimate. A high-temperature combustion process can reduce VOC and CO levels to below 100 and 300 ppmv, respectively. Venturi scrubbers can achieve over 99% particulate control. Flare performance has never been adequately measured so that the level of control of various species is purely speculative. Since levels of VOC, CO, organic aerosols, and coal dust are not well known, the cost effectiveness of any of the controls for low-pressure lockhopper gas cannot be determined. Control of high-pressure lockhopper gas is cost effective under any assumed level of pollutant reduction since recovered energy offsets control costs.

4.1.2.2 Transient (Startup, Shutdown, and Upsets) Waste Gases

Control options for waste gases which occur during startups, shutdowns, and upset conditions differ from those for continuous sources. Because of the intermittent nature (estimated to occur over approximately 400 hours throughout the typical operating year) and variable composition of the waste gases, proper operation and performance of many types of controls may be hampered. Additionally, waste gases emitted during startups, shutdowns, and upset conditions may sometimes be explosive (generally defined for combustible gases when the O_2 content exceeds 2%), thus requiring special design in ductwork and fans for flashback control.

Since Lurgi gasifiers are often started with air rather than oxygen for gasification, the composition of transient gases is expected to be similar to that for air blown Lurgi gasifiers. From a pollution control standpoint, the waste gas is similar to raw Lurgi gas or lockhopper gas except that it is diluted with nitrogen. The diluent nitrogen also lowers the heating value of the gas so that an energy penalty, or downrating of heat recovery equipment, would be necessary when the gases are incinerated with heat recovery. Compared to coal, about 6% less of the enthalpy of combustion (LHV) can be recovered using the same heat exchange units. The inerts in the transient gas also result in a flue gas which is more than twice the volume of that from an equivalent amount of coal (LHV basis). Thus, all heat exchange equipment would have to be correspondingly larger and would be more costly.

Incineration of transient gases can be accomplished in boilers, superheaters, dedicated incinerators, or flares. Since the degree of heat recovery in large boilers/superheaters is generally higher than with gas incinerators and since maximum steam load in a Lurgi facility occurs at the same time in which startup transients occur, there is considerable incentive to burn these gases as fuel in plant boilers.

Table 4-9 presents the estimated costs for incineration of transient gases. For incineration in the boiler, incremental capital costs have been assumed to be proportional to flue gas volume (relative to coal). Unlike the case of high pressure lockhopper gases, recovered energy does not offset the fixed capital cost. This is because so little energy is recovered from transients on an annual basis. The situation becomes more costly when sulfur removal from the flue gas is included, since FGD units would have to be designed for larger flue gas volumes. It should be noted that calculating incremental costs in direct proportion to increased flue gas flow probably results in overestimates. However, even when the engineering "six-tenths power" rule of thumb for cost as a fraction of size is applied, the overall results are not changed dramatically. Thermal incineration of the transient gases also incurs high costs relative to the annual volume of gases handled. Flaring is the least expensive option, particularly when the flare cost is shared among several waste gases in an integrated facility.

TABLE 4-9. COSTS ASSOCIATED WITH INCINERATION OF TRANSIENT WASTE GASES

Control Technique	Estimated Control Costs[a]				
	Total Capital	Total Annual Operating	Total Annualized	Percent of Base Plant Costs	
				Capital	Total Annualized
Boiler or Superheater	10.3	0	1.8	1.26	0.9
Boiler Plus ESP/FGD	17.3	1.3	4.3	2.11	2.15
Thermal Incinerator	3.6	0.06	0.68	0.44	0.34
Thermal Incinerator Plus ESP/FGD	4.1	0.07	0.78	0.50	0.39
Flare	0.44	0.01	0.09	0.05	0.04

[a] Costs are millions of first quarter 1980 dollars.

4.1.2.3 Depressurization and Stripping Gases

When Lurgi gas liquor is steam stripped for ammonia removal/recovery, a stripping gas is generated which contains H_2S, HCN, NH_3, and organics derived from the aqueous phase. After ammonia removal, the waste gas may either be incinerated or combined with Rectisol acid gases for sulfur removal. It is expected that direct routing of such gases to sulfur recovery will be practiced at gasification facilities, as this is common practice in both petroleum refineries and coke plants.

Offgases from gas liquor separation also contain both combustibles and reduced nitrogen and sulfur compounds. Such gases may be directly incinerated, combined with Rectisol acid gases for sulfur control, or routed to the ammonia recovery section of water pollution control facilities. The latter alternative is most attractive since these offgases would not add appreciably to the cost of the stripping/ammonia recovery unit. The combined ammonia recovery overhead would be either incinerated, sent to bulk sulfur recovery, or sent to sulfur recovery tail gas treatment.

Costs for control of the subject gases are not readily calculated since their combination with larger volume Rectisol acid gases or gasifier waste gases makes cost breakdown difficult. Their volumetric flow would add only a few percent to the load of a typical sulfur recovery unit so that incremental costs might be assigned in the same proportion. A similar problem arises with costs for flaring or incineration, since these small volume streams would be combined with other gases for control rather than separately handled.

4.1.2.4 CO_2-Rich Gases from SNG Production

When byproduct gases from synthesis operations are methanated, CO_2 removal may be necessary to obtain pipeline quality gas. From 22 to 76 kmols/hr of CO_2 gas are generated in the methanol and Mobil M-gasoline gases, and about 260 kmols/hr in the Fischer-Tropsch case. These gases contain about 1000 ppmv VOC and 3% methane. Either thermal or catalytic incineration would achieve about the same degree of VOC control. A capital investment of $270,000 and an annual operating cost (primarily fuel) of $39,000 are estimated. Catalytic incineration incurs larger capital costs, but these are largely offset by fuel savings, so that total annualized costs for both incineration approaches are similar.

4.1.3 Transient Process Gas Containing SO_2, CO and/or Particulates

Lurgi synthetic fuels facilities have several intermittent sources of SO_2, CO, and/or particulates which result from regeneration or decommissioning of catalysts or related materials. Cobalt molybdate based shift catalysts are active in the sulfided state, and the sulfur is released as SO_2 when such catalysts are regenerated with air and steam to burn off coke. Mobil M catalysts are also regenerated with air and steam to remove coke, but no sulfur is present in this case. Some CO and, during purging of either the shift or Mobil M units, some VOC may be contained in the offgases. Methanation catalyst is not normally regenerated, but it is oxidized in a controlled manner when its useful life has ended. The reduced form of the catalyst is pyrophoric which would create handling/disposal problems unless the material is stabilized prior to removal from the catalytic unit. In a few existing facilities, Claus catalysts have been regenerated, resulting in a sulfur-containing offgas. When activated carbon is employed for wastewater treatment, an offgas is generated when the carbon is regenerated with air and steam.

Controls for these intermittent waste gases are difficult to evaluate due to their uncertain character and frequency of generation, and because such waste gases are not usually treated in refineries, coke plants, or in other industries where similar units are found. Thus, little direct experience exists upon which to base an assessment of control possibilities, performance, or costs. In the case of SO_2, controls which would be possible include FGD processes such as those used for boilers or Claus plant tail gases and the use of the Claus process itself. These processes are described in Sections 4.1.1 and 4.1.4. Incineration for CO and VOC control is also described in Section 4.1.1. Controls for particulates are discussed in Section 4.1.4. The following is an evaluation of such controls as applied to the major intermittent waste streams (shift and Mobil M catalyst and carbon regeneration offgases).

4.1.3.1 Shift Catalyst Regeneration Offgases

Shift catalysts are periodically regenerated with air and steam to burn off accumulated coke and sulfur and to allow safe access of maintenance personnel to the shift reactors. The offgas is over 90% steam but contains about 13% SO_2 on a dry basis. Regeneration offgas would be produced over several hours and occurs an average of 7% of the plant operating time. About 150 kmols/hr of dry gas containing 1700 kmols of steam is an estimated flow rate for purposes of sizing controls.

Since the shift unit(s) contain interstage quenching for temperature control, it is entirely reasonable to envision operation of the quench system during regeneration to condense moisture from the offgas. Removal of most of the moisture would be desirable for purposes of volume reduction, prevention of condensation in piping to controls, and to avoid problems in controls themselves with high moisture levels.

Control of the offgas after bulk moisture removal can be accomplished using onsite Claus units. The SO_2 in shift regeneration gases could displace SO_2 produced by air oxidation of H_2S in the Claus units. Since the maximum SO_2 load from regeneration gases is about 20 kmols/hr, while sulfur in Rectisol acid gases is 100 to 180 kmols/hr, there is sufficient Claus capacity to allow substitution of regeneration gases for SO_2 produced by air oxidation. The following represents the Claus oxidation step with air.

$$H_2S + 1.5\ O_2 + 5.64\ N_2 \longrightarrow SO_2 + H_2O + 5.64\ N_2$$

Notice that oxidation of one kmol of H_2S produces 6.64 kmols of inert gases which ordinarily would be carried through the Claus unit. Since one kmol of SO_2 in shift regeneration gas (dry basis) at 13% SO_2 carries 7.7 kmols of inert gas into the Claus unit, the addition of the waste gas to Claus feed increases the inert volume in the Claus plant only by about 1 kmol per kmol SO_2 added. Claus tail gases in the subject facilities are 500 to 1000 kmols/hr so that essentially no increase in Claus plant size is necessary to accommodate the shift offgas. Of course, the increased sulfur load at constant volume will increase Claus plant capital and operation costs slightly, but no large cost impact is expected at the Claus plant for handling the waste gas. Claus tail gas treatment units would also experience a higher sulfur load but essentially no increase in volumetric throughput. It should be remembered that water vapor in Claus feeds not only acts as an inert but also reduces the thermodynamic efficiency of the Claus reaction. By not removing the bulk of the moisture from the shift offgas, the Claus plant would have to be larger and would operate at a lower efficiency.

Shift offgases may be treated by SO_2 removal processes (e.g., Wellman-Lord) used on site for boiler SO_2 control or for Claus plant tail gas sulfur control. In the case of a boiler FGD, the volumetric flow rate increases by only 1 to 2%, but the sulfur loading would almost double. In the case of a Claus tail gas treatment unit, flow would increase by about 3 to 5% and sulfur load would increase by about 60%. Costs for SO_2 removal processes are influenced by both volumetric flow rate and sulfur load so that a detailed evaluation would be required to determine the relative costs of boiler vs. Claus tail gas FGD as controls for sulfur offgases.

Since the subject waste gas is small in volume and intermittent, a dedicated caustic scrubber is also feasible for SO_2 control. Moisture removal would not be as critical with a dedicated unit as with the use of Claus or FGD units elsewhere in the facility. Although caustic is expensive, the amount needed on an annual basis is not large, so that a "throwaway" approach has merit.

Table 4-10 summarizes the costs for both dedicated and integrated control of shift offgases. The estimates indicate that Claus sulfur control is more expensive than FGD and that dedicated FGD units are more cost effective than existing units in an integrated facility. The low cost of a throwaway caustic scrubber largely reflects the small volume of the stream on an annual basis. It should be noted that SO_2 control via a dedicated Claus plant requires reducing gas and a catalytic conversion unit to convert SO_2 to H_2S. A commercial version of this approach is licensed by Allied Chemical Corporation. Indeed, Wellman-Lord FGD units feature this technology for ultimate recovery of elemental sulfur in boiler applications where a Claus plant is not available.

There are currently a number of installations using sour shift catalysts in petroleum and related applications. As far as is known, control of regeneration offgases is not practiced at any of the facilities. Catalyst users indicate that, due to the short duration and high variability of SO_2-containing offgases, control would be difficult. Regeneration often occurs when facilities are shut down for general maintenance, so that use of FGD or Claus units on site at such time presents difficulties. Even if regeneration of catalyst units were to be scheduled during times in which FGD or Claus units were online, integration of the highly variable regeneration gases into such units would make overall system control difficult and performance less than usual. For these reasons, in the first Lurgi gasification facility for the U.S. (Great Plains Project), there are no plans to control regeneration offgases.

TABLE 4-10. COSTS FOR CONTROL OF SO_2 IN SHIFT CATALYST REGENERATION OFFGASES

Control Technique	Estimated Control Costs[a]				
	Total Capital	Total Annual Operating	Total Annualized	Percent of Base Plant Costs	
				Capital	Total Annualized
Dedicated Claus[b]	5.7	0.03	1.01	0.7	0.5
Combined Claus[c]	1.43	0.03	0.28	0.18	0.14
Dedicated FGD (Wellman-Lord)	1.25	0.02	0.23	0.14	0.11
Dedicated Caustic Scrubber	0.15	0.14	0.15	0.02	0.08

[a] Costs are millions of first quarter 1980 dollars.

[b] Includes reducing gas and catalytic unit for converting 2/3 of the SO_2 to H_2S.

[c] SCOT basis.

4.1.3.2 Mobil M Catalyst Regeneration Offgases

Limited information is available on the frequency of catalyst regeneration and offgas volume and CO content expected in a Lurgi-based Mobil M gasoline facility. Residual organics and particulates may also be present in the gas during purging of the unit or initial phases of regeneration. For VOC or CO control, either thermal or catalytic incineration are prime candidates. Table 4-11 summarizes the costs estimated for control of Mobil M-offgas. If the particulate loading of the gas is low, catalytic incineration offers cost savings compared to thermal incineration.

TABLE 4-11. COST ESTIMATES FOR CONTROL OF MOBIL CATALYST DECOMMISSIONING OFFGAS

	Estimated Control Costs[a]				
				Percent of Base Plant costs	
Control Technique	Total Capital	Total Annual Operating	Total Annualized	Capital	Total Annualized
Thermal Incineration[b]					
Without ESP	0.26	0.03	0.08	0.03	0.04
With ESP	0.7	0.05	0.17	0.08	0.08
Catalytic Incineration	0.18	0.03	0.06	0.02	0.03
Flare	0.1	0.03	0.05	0.01	0.02

[a] Costs are millions of first quarter 1980 dollars.
[b] No heat recovery.

4.1.3.3 Carbon Regeneration Flue Gases

When granular activated carbon is used for water pollution control, regeneration of the carbon with steam and air is required on a periodic basis. The exact schedule for regeneration will depend on the wastewater flow and loading. An annual average of about 200 kmols/hr is expected for the subject facilities with regeneration occurring about 10% of the operating time. The regeneration offgases contain unburned organics, CO, and carbon dusts which are controlled in existing applications by incineration and particulate scrubbers.

Table 4-12 presents cost estimates for control of the offgases. Thermal incineration is seen to be less costly than catalytic incineration for streams of the size encountered. Particulate control via ESP either before or after incineration can significantly increase the costs.

TABLE 4-12. COST SUMMARY: CARBON ABSORPTION REGENERATION OFFGAS

	Estimated Control Costs[a]				
				Percent of Base Plant Costs	
Control Technique	Total Capital	Total Annual Operating	Total Annualized	Capital	Total Annualized
ESP/Thermal Incineration	1.38	0.10[b]	0.34[b]	0.17	0.17
ESP/Catalytic Incineration	2.69	0.14	0.60	0.33	0.30
Venturi/Catalytic Incineration	2.13	0.14	0.50	0.26	0.25
Flare	0.43	0.13	0.20	0.05	0.10

[a] Costs are millions of first quarter 1980 dollars.
[b] Includes energy recovery credit.

4.1.4 Combustion Gases

The major pollutant species associated with the combustion of fossil fuels are SO_2, NO_x, and particulates. Sulfur dioxide is formed rapidly in the combustion process when sulfur contained in the fuel reacts with oxygen in the air. Variations in the combustion process are not effective in reducing SO_2 emissions. Rather, sulfur must be removed from the fuel, or, once formed, SO_2 must be removed from the exhaust gas.

The generation of NO_x from air-fed fuel combustion processes occurs by two separate mechanisms, identified as thermal NO_x and fuel NO_x. Thermal NO_x results from the thermal fixation of molecular nitrogen and oxygen in the combustion air and is sensitive to flame temperatures and to local concentrations of oxygen. Fuel NO_x is created from the oxidation of chemically bound nitrogen in the fuel being combusted. Fuel NO_x formation is strongly affected by the rate of mixing of the fuel and air and by the local oxygen concentration. Approximately 95% of oxides of nitrogen from combustion are emitted as NO (56,57).

Particulates generated during combustion result mainly from the ash content of the fuel. The magnitude of these emissions in the flue gas is a function of fuel ash content and combustion unit design. Particulate emissions are negligible when gaseous or oil-based fuels are used.

The major sources of flue gases from a coal gasification facility are the plant power boiler, process heaters, and secondary combustion gas streams from other media. It should be emphasized that combustion of fuels is not unique to coal gasification facilities and, generally, presents no new problems for emission control over those encountered in any other industrial application.

NO_x Control

NO_x pollution control techniques are of two types: 1) combustion modifications to limit nitrogen conversion to NO_x and 2) flue gas treatment. Combustion modification techniques are the most widely used. They can achieve from 25 to 60% reduction in NO_x emissions. Some of the most common of these techniques are 1) low excess air, 2) staged combustion, 3) flue gas recirculation, 4) reduced load, 5) low NO_x burners, and 6) ammonia injection. The key features and unit costs of these techniques as applied to coal- and oil-fired combustors are discussed in Table 4-13.

The cost of combustion modification techniques for controlling NO_x emissions depends upon the additional hardware required and any changes in operational procedures that may increase the cost of steam production. Cost estimates for combustion modification techniques are included in Table 4-13. For more detailed information, other EPA studies should be consulted.

Flue gas treatment techniques have been proposed for control of NO_x emissions to levels significantly below those achievable by combustion modification techniques. Although large scale flue gas treatment schemes have not been proved commercially in the U.S., these techniques are being applied in Japan. The key features of some of these processes are provided in Table 4-14. Additional flue gas treatment techniques are discussed in the Control Technology Appendices for Pollution Control Technical Manuals.

TABLE 4-13. COMBUSTION MODIFICATION TECHNIQUES FOR NO_x CONTROL

Control Technique	Description of Technique	% NO_x Reduction (Type of Fuel Fired)[a]	Range of Application	Stage of Development	Capital Cost[b] (per MW of heat input)	Limitations and Comments
Low Excess Air (LEA)	Combustion air is reduced to the minimum amount required for complete combustion while maintaining proper stream temperature.	0 - 25 (PC)	Excess O_2 lowered to 5.2% on the average.	Available but implemented on a limited basis only.	$440 to $550	Limited by increase in CO, HC, and particulate emissions. Increase in boiler efficiency may be achieved as a benefit.
		0 - 28 (RO) 0 - 24 (DO)	Excess O_2 can be reduced to 2.5%.	Available.	$460 to $2400	Added benefits include increase in boiler efficiency. Limited by increase in CO, HC, and TSP emissions.
Staged Combustion Overfire Air Injection (OFA)	Injection of air above the top burner level through OFA ports together with a reduction in air flow to the burners (staged combustion).	5 - 30 (PC)	Burner stoichiometry as low as 100%.	Available but not demonstrated.	$800 to $940	Limited by possible increase in slagging and corrosion. Excess air may be required to ensure complete combustion thereby decreasing efficiency.
Staged Combustion Air (LEA + OFA)	Fuel-rich firing burners with secondary combustion air ports.	20 - 50 (RO) 17 - 44 (DO)	70-90% burner stoichiometry can be used with proper burner installation.	Technique is applicable on packaged and field-erected units. However, not commercially available for all design types.	$870 to $5150	Best implemented on new units. Retrofit is probably not feasible for most units especially packaged ones.
Air and Fuel-Rich Firing	One or more burners fired on air only. Remainder of burners firing fuel rich.	27 - 39 (PC)	Boilers must have a minimum of 4 burners or be designed with excess burners.	Available, but engineering refinement is needed prior to implementation.	Not available	Load reduction required in most cases. Possible increased slagging and corrosion. New boiler design will incorporate the required number of burners.

(Continued)

TABLE 4-13. (Continued)

Control Technique	Description of Technique	% NO_x Reduction (Type of Fuel Fired)[a]	Range of Application	Stage of Development	Capital Cost[†] (per MW of heat input)	Limitations and Comments
Flue Gas Recirculation (FGR)	Recirculation of the flue gas to the burner windbox.	0 - 20 (PC)	A maximum of 25% of the flue gas can be recirculated.	Not offered because the method is comparatively ineffective.	Not available	Flue gas recirculation lowers the bulk furnace gas temperatures and reduces O_2 concentration in the combustion zone. Requires installation of flue gas recirculation ducts, fans, insulation, etc. May cause combustion instability.
		15 - 30 (RO) 58 - 73 (DO)	Up to 25-30% of flue gas recycled. Can be implemented on all design types.	Available. Requires extensive modifications to the burner and windbox.	$1070 to $5150	Best suited for new units. Costly to retrofit. Possible flame instability at high FGD rates.
Reduced Load (RL)	Reduction of fuel and air flow to the burner.	Up to 45% (PC)	Load may be reduced to 25% of capacity.	Available but not implemented because of negative operational impacts.	Not available	Best used with increase in firebox for new boilers. Load reduction may not be effective because of increase in excess O_2.
		33% decrease to 25% increase (RO) 31% decrease to 17% increase (DO)	Applicable to all boiler types and sizes. Load can be reduced to 25% of maximum.	Available now as a retrofit application. Better implementation with improved firebox design.	Not available	Technique not effective when it necessitates an increase in excess O_2 levels. RL is possible to implement in new designs as reduced combustion intensity (enlarged furnace plan area).
Low NO_x Burners (LNB)	New burner designed to utilize controlled air-fuel mixture.	45 - 60 (PC)	Prototypes are limited to size ranges >30 MW.	Development stage prototypes are available from major boiler manufacturers.	$800 to $940	Low NO_x burners could maintain the furnace in an oxidizing environment to minimize slagging and reducing the potential for furnace corrosion. More complete carbon utilization results because of better coal/air mixing in the furnace. Lower O_2 requirements may be obtained with all the combustion air admitted through the burners.

(Continued)

TABLE 4-13. (Continued)

Control Technique	Description of Technique	% NO_x Reduction (Type of Fuel Fired)[a]	Range of Application	Stage of Development	Capital Cost[b] (per MW of heat input)	Limitations and Comments
Low NO_x Burners (LNB) (Continued)		20 - 50 (RO) 20 - 50 (DO)	New burners described generally applicable to all boilers.	Commercially offered but not demonstrated.	$860 to $5150	Specific emissions data from oil-fired industrial boilers equipped with LNB are lacking.ped with LNB
NH_3 Injection	Injection of NH_3 into convective section of the boiler.	40 - 60 (PC)	NH_3 injection rate limited to NH_3/NO = 1.5	Commercially offered but not demonstrated.	$4800	Limited by furnace geometry. Performance is sensitive to flue gas temperature and residence time at optimum temperatures.
		40 - 70 (RO) 40 - 70 (DO)	Applicable for large package and field-erected watertube boilers.	Commercially offered but not demonstrated.	$4940 to $9770	Some increased maintenance of air heater/economizer parts might be necessary when burning high sulfur oil. Technique is very costly. Byproduct emissions such as ammonium bisulfate could cause operational problems.

[a] PC - pulverized coal, RO - residual oil, DO - distillate oil.

[b] Costs are first quarter 1980 dollars.

TABLE 4-14. NO_x FLUE GAS TREATMENT CONTROL ALTERNATIVES FOR BOILERS

Control Technique	Description of Technique	% NO_x Reduction	Applicability	Stage of Development	Capital Costs (for 20 MW)[a]	Limitations and Comments
Selective Catalytic Reduction (SCR) - Fixed Packed Bed Reactors[b]	Utilizes NH_3 to selectively reduce NO_x to N_2. Reactor contains ring shaped catalyst pellets packed in fixed bed.	Up to 90%	Applicable only to flue gas streams containing particulate emissions of less than 20 mg/Nm³.	Commercially available only for natural gas-fired boilers at this time.	\$155/kW (coal) \$84/kW (oil)	Fixed bed SCR systems are not considered for application to coal-fired boilers.
- Parallel Flow Reactor[b]	Utilizes NH_3 to selectively reduce NO_x to N_2. Reactor contains a special catalyst arrangement (honeycomb, parallel plate, or tubes).	Up to 90%	Testing currently under way for high particulate (>1 g/Nm³) flue gas.	Has been applied in Japan to several oil-fired industrial and utility boilers. Applicability to coal-fired boilers currently being tested by EPA.	\$53/kW (coal) \$45/kW (oil)	Greatly reduces particulate impaction as gas flow is parallel to catalyst surface. Unreacted NH_3 downstream can react with SO_2 or SO_3 to form ammonium bisulfate or the NH_3 could enter FGD and ESP equipment.
- Simultaneous Removal[b] of NO_x/SO_x	Utilizes NH_3 to catalytically reduce NO_x after SO_x is absorbed and reacted with catalyst. Uniquely designed parallel flow reactor used to avoid particulate problems.	80% NO_x; 90% SO_x (theoretical)	Should be applicable to high particulate flue gas.	No continuous coal-fired NO_x removal test data for NO_x/SO_x systems are available.	\$567/kW (coal & oil)	System is not affected by changes in the boiler gas flow rate or partriculate concentrations. Changes in NO_x concentration because of boiler load changes may be compensated for by conventional control system used with the NH_3 injection equipment.
Electron Beam Radiation NO_x/SO_x Removal[c]	A dry process that utilizes an electron beam to bombard the flue gas, thereby removing NO_x and SO_2.	Removal efficiency will decrease as NO_x and SO_2 increase.	Byproduct (ammonium nitrate and ammonium sulfate powder) treatment technology needs to be more fully developed before commercialization.	No coal-fired tests have been performed at this time.	\$241/kW (coal)	NO_x/SO_2 removal will drop off drastically at low radiation doses based on oil-fired pilot tests. Sulfate and nitrate salts as well as other ionic species formed as byproducts.

[a] Costs are first quarter 1980 dollars.

[b] Spent catalyst is secondary waste.

[c] Ammonium nitrates and sulfates are secondary wastes.

SO_2 Removal

Several flue gas desulfurization (FGD) processes are commercially available. They are basically of two types: 1) throwaway systems which produce a waste sludge byproduct, and 2) regenerable systems which produce a usable sulfur byproduct and regenerate the sorbent. Examples of throwaway systems are the lime/limestone, double alkali, fly ash alkalinity, and Chiyoda Thoroughbred 121. Regenerable systems include the Wellman-Lord and magnesium oxide processes. Key features of some of these scrubbing systems are presented in Table 4-15.

The lime/limestone scrubbers are the most commonly employed throwaway systems for electric utility applications. In the lime/limestone process, solid lime or limestone is pulverized and mixed with water to form a scrubber liquor, which contacts the flue gas in an absorption tower where calcium sulfate and calcium sulfite are formed. The resulting slurry is removed from the system and treated, and the sludge is disposed of. Scrubbing solution is recovered and recycled to the absorption tower. Lime/limestone removal efficiencies can approach 90% by carefully balancing the many chemical-reaction parameters involved. Of the throwaway FGD systems available, lime/limestone offers the least complex system and equipment, the easiest pH control, and the cheapest raw materials. Operating experience has indicated that careful attention to system control is important for successful operation of lime/limestone FGD systems.

Of the commercially available regenerable FGD systems, Wellman-Lord is the most extensively used. A venturi prescrubber often preceeds the Wellman-Lord absorber to remove residual particulates from the flue gas and avoid ash accumulation in the absorber. Sulfur dioxide is absorbed by an alkaline

TABLE 4-15. KEY FEATURES OF SO_2 REMOVAL PROCESSES

Process Feature	Lime/Limestone Scrubbing	Double Alkali Scrubbing	Chiyoda Thoroughbred 121	Wellman-Lord	Dry Scrubbing	Fly Ash Alkalinity Scrubbing
Principle	Liquid phase absorption of SO_2 in lime or limestone slurry.	Liquid phase absorption of SO_2 in a sodium hydroxide, sodium sulfite, sodium bisulfite, sodium sulfate, and sodium carbonate solution. Regeneration of the sodium sulfite/bisulfite with lime in a reactor. A dilute mode can be used for concentrations of 200-1500 ppm SO_2 and where less than 25% oxidation of sulfite to sulfate occurs. Concentration mode can be used for concentrations of 1000-8000 ppm SO_2.	Liquid absorption of SO_2 in a single vessel, where limestone addition and dissolution, air oxidation, and gypsum precipitation occur.	Liquid phase absorption of SO_2 in a sodium bisulfite, sodium sulfite, and sodium carbonate solution. A rich SO_2 is produced by evaporation, which is then processed in a Claus unit to produce elemental sulfur or in a sulfuric acid plant.	Process involves the use of a spray dryer which contacts the flue gas with an aqueous alkaline material and produces a dry product. System involves two stages: 1st stage-spray dryer; 2nd stage-dry particulate collector which removes flue ash and reaction product from flue gas.	Process involves a two stage venturi-spray tower absorber utilizing the fly ash alkalinity for SO_2 removal. Hydrated dolomitic lime, ($Mg(OH)_2$ and $Ca(OH)_2$) is also used to achieve an outlet SO_2 of 43 ng/J.
Feed Stream Requirements	Particulate can be removed in an EPS or fabric filter to achieve 99+% at lowest energy consumption. Fly ash may be removed in a venturi where the fly ash contains significant alkalinity. A scrubber can be used for both high particulate and SO_2 removal.	Excessive particulates should be removed in an ESP, fabric filter or venturi. O_2 should be less than 7% for concentrated mode.	Particulates and chlorides should be removed from inlet flue gas if byproduct gypsum is to be sold.	Particulates and chlorides must be removed from flue gas.	Inlet SO_2 concentration should not exceed 1000 ppmv.	Venturi is used to remove particulates and a portion of SO_2
Absorbent	Slaked lime or 200-300 mesh limestone 6-12% slurry circulated.	Sodium hydroxide, sodium sulfite/bisulfite, and a small amount of sodium sulfate.	Limestone slurry.	Concentrated sodium sulfite/bisulfite.	Lime slurry or sodium carbonate solution.	Fly ash alkalinity and hydrated lime (calcium and magnesium hydroxide).
Product/Waste	Gypsum can be produced with forced oxidation. Calcium sulfate/sulfite can be produced with 50-70% solids.	Filter cake with 60-70% solids, primarily calcium sulfite and calcium sulfate.	Gypsum ($CaSO_4 \cdot 2H_2O$) with less than 20% moisture content.	Concentrated SO_2 purge stream (90% SO_2).	Sodium sulfite-sodium sulfate; calcium sulfite/sulfate.	Sludge consists of fly ash, gypsum ($CaSO_4 \cdot 2H_2O$), $(Mg(OH)_2$, small amount of calcium sulfite.

(Continued)

TABLE 4-15. (Continued)

Process Feature	Lime/Limestone Scrubbing	Double Alkali Scrubbing	Chiyoda Thoroughbred 121	Wellman-Lord	Dry Scrubbing	Fly Ash Alkalinity Scrubbing
Efficiency	90% removal can be obtained generally for low and high sulfur coals. Higher removals can be obtained with higher L/G and pressure drop, and to some extent scrubber type. 90% and greater can be obtained for low sulfur coals. 95% removal for high sulfur coals when adipic acid is used. Commercially demonstrated in over 30 FGD units.	90-99% removal can be obtained for low and high sulfur coals. Concentrated mode has been demonstrated at Louisville Gas & Electric's 200 MW coal-fired boiler. Smaller industrial units (General Motors) have been operated in the dilute mode.	90% SO_2 removal or outlet SO_2 equal to 300 ppmv. Process has been demonstrated in Gulf Power's Scholz station - 20MW prototype.	Process has been demonstrated in a NIPSCO 115MW coal-fired boiler. Can remove up to 95% SO_2	70% SO_2 removal using lime as absorbent. 80% SO_2 removal using sodium absorbent.	85-90% removal of SO_2 commercial demonstrated in Montana Power's Colstrip 1 & 2. 95+% expected in Colstrip units 3 & 4.
Cost[a]	Capital - $90/kW to $185/kW.	Capital - $101/kW to $163/kW.	Capital - $160/kW.	Capital - $138/kW to $265/kW.	Capital - $23/kW to $47/kW.	Not available.
Advantages	Lower capital cost and O&M costs. SO_2 and particulates can be removed simultaneously. Relatively simple process.	Lower capital and O&M costs. SO_2 can be removed to very high efficiencies (99%). Conventional process equipment.	Capital and O&M costs appear to be competitive but data limited to prototype experience. Potential saleable gypsum by-product.	Commercially demonstrated. Process produces saleable product sulfur with a Claus unit or sulfuric acid. Lower potential for scaling than calcium system.	Lower projected operating and capital costs. Dry product.	Commercially demonstrated in 300MW units. Sludge contains little calcium sulfite which improves dewatering and therefore reduces settled water content. Less potential for scaling.
Disadvantages	Process produces approximately 2 times (by wt) sludge as ash collected. Sludge can be thixotropic. Sludge quantities can be reduced by forced oxidation.	Process produces 1.5 times (by wt) filter cake as collected ash. 316SS material of construction may be required to prevent corrosion and pitting.	Process has not been demonstrated commercially in a 100MW or larger unit.	High utility costs (steam) compared to other systems. Special metallurgy may be required. System required to process SO_2 to sulfur or sulfuric acid.	Process will not be commercially demonstrated until late 1982. Product disposal could be a problem when sodium salts are used as absorbents.	Process is generally applied to coal-fired boilers which burn high alkalinity coals.

[a] Costs are first quarter 1980 dollars.

sodium sulfite solution to produce primarily sodium bisulfite. This bisulfite-rich solution is then pumped to a forced-circulation vacuum evaporator where it is indirectly heated by steam to convert the bisulfite to sulfite and gaseous SO_2. A portion of the sodium sulfite is also converted irreversibly to sodium sulfate and thiosulfate which must be purged from the system, requiring a makeup of NaOH or $NaCO_3$. The Wellman-Lord process can achieve over 90% SO_2 removal.

Dry scrubbing experience to date has been limited, although systems that have been operated show much promise, especially for low- and medium-sulfur coals (58). The spray drying process is the only dry scrubbing process currently being offered commercially. In this process the absorbent solution, usually either lime or soda ash, is atomized and sprayed into the incoming flue-gas stream to increase the liquid/gas interface and promote mass transfer between the SO_2 and the slurry droplets. Simultaneously, the thermal energy of the gas stream evaporates the water in the atomized droplets to produce a dry, powdered mixture of sulfite/sulfate and unreacted reagent. When used in combination with fabric filters these systems have performed extremely well. The fabric filter collects the particulates and also recovers some of the expensive reagent which is reused. In addition, unused reagent that cakes on the fabric is available to react with more SO_2 as flue gas passes through it.

FGD costs for boilers in synfuel plants will depend upon the amount of sulfur emissions control required. This may vary depending upon the amount of sulfur in the fuel. FGD cost data have been developed by the EPA for electric utility steam generating units ranging in size from 25 MW_e to 1000 MW_e. The cost variations are principally governed by 1) size of the boiler, 2) coal used, 3) averaging time over which the plant must meet SO_2 limitations, and 4) the level of control maintained. Capital investment and annual operating costs for lime/limestone and Wellman-Lord FGD systems are listed in Table 4-15.

Particulate Removal

The choice of the particulate collection equipment depends upon a number of factors: the properties of the materials such as particle size and physical and chemical properties; the concentration and volume of the particulate to be handled; the temperature and humidity of the gaseous medium; and most importantly, the collection efficiency desired.

There are four basic types of particulate collection equipment: 1) cyclones, 2) fabric filters/baghouses, 3) venturi scrubbers, and 4) electrostatic precipitators. The key features and unit costs of these collection devices are presented in Table 4-16.

Cyclones are generally employed for the removal of bulk particulates (usually greater than 4 microns in size) and, in many cases, precede other control devices. The unit installed costs of cyclones are relatively low, approximately $\$212/m^3/min$.

Baghouses have very high particulate removal efficiencies and lend themselves to applications involving small or intermittent gas flows. Baghouses, however, have high pressure drops (in comparison with electrostatic precipitators) and cannot ordinarily handle wet gases, gases containing oily materials, or gases having temperatures in excess of 573 K. Installed cost for a typical baghouse unit is about $\$300/m^3/min$.

Venturi scrubbers can generally handle gases having temperatures higher than those which can be handled by fabric filters, can operate at high pressure, can tolerate wet and dry gases, and can be very efficient for the removal of submicron particles. In contrast to devices in which the particles

TABLE 4-16. KEY FEATURES OF PARTICULATE COLLECTION EQUIPMENT

	High Efficiency Cyclone	Fabric Filter (Baghouse)	Venturi Scrubber	Electrostatic Precipitator
Operating Principle	Particulates removed from gas stream by imparting a centrifugal force. The inertia of the particulates carries them to the walls where they fall to the bottom of the cyclone for removal.	Fabric filter material is arranged in a tubular shape with the particulate-laden gas stream passing through the filter. Particulate removal primarily results from the buildup of collected material on the dirty-air side of the filter. The filter is periodically cleaned by mechanical shaking or a pressurized reverse air flow.	Removal of particulates from a gas stream by intimate contact with multiple jet streams of scrubbing water and droplets. Agglomerated particulates are subsequently removed in a centrifugal and/or mist eliminator.	A negative electrical charge is imparted to the particulates and they are collected on positively charged plates. Collected material is removed by periodically rapping or vibrating the collection plates.
Removal Efficiency Range (weight %)	50 to 80% for >5 µm. 80 to 95% for 5 to 20 µm.	98.5 to 99.5% for 0.25 to 0.5 µm. 99 to 99.5% for 0.75 to 1 µm. 99.5 to 99.9% for 3 µm. 99.95% for >3 µm.	50 to 92.5% for 0.25 µm. 60 to 98% for 0.5 µm. 70 to 99% for 0.75 µm. 90 to 99.6% for 3 µm.	95 to 99% for 0.1 µm. 90 to 96% for 0.5 µm. 95 to 99% for 1 µm. 99 to 99.9% for 5 µm.
Inlet Loading Limitations (g/Nm^3)	>2.4	>0.24	>0.5	>0.24
Normal Pressure Drop Range (cm H_2O)	7 to 20	5 to 25	13 to 250	0.5 to 2.5
Reliability or Other Limitations	Cannot effectively remove particulates smaller than 5 µm.	Plugging problems will result if condensation occurs on filter media or if hygroscopic-material is collected. Temperature limit varies with type of filter media used, maximum is 560 K.	Reliability may be limited by scaling, fouling, or corrosion. Scrubbing liquor blowdown may require treatment or contain potentially valuable material not directly recoverable.	Not applicable to combustible or potentially explosive mixtures. Particulates to be collected must have suitable electrical resistivity to facilitate efficient removal. Used in low pressure applications. Limited to gas streams with temperatures below 700 K.
Secondary Waste	Collected particulates.	Collected particulates.	Scrubbing liquor blowdown and wet slurry.	Collected particulates.

(Continued)

TABLE 4-16. (Continued)

	High Efficiency Cyclone	Fabric Filter (Baghouse)	Venturi Scrubber	Electrostatic Precipitator
Installed Costs[a]	About $\$212/\text{m}^3/\text{min}$ for total installed system.	About $\$282/\text{m}^3/\text{min}$ for total system.	About $\$250/\text{m}^3/\text{min}$ (increasing cost with removal efficiency).	About $\$250$ to $\$530/\text{m}^3/\text{min}$ (increasing cost with increasing removal efficiency).
General Comments	High reliability due to operating principle with no moving parts. Low energy requirements.	High particulate removal efficiency. High installation cost. Large scale required.	High particulate removal efficiency. Capable of treating streams with wide ranges in temperature (no limitation for high temperatures), pressure, and gas composition. High efficiencies require high energy consumption.	High particulate removal efficiency, especially the submicron range. High capital and installation costs. Very low pressure drop. Suitable for high temperature or large volume applications. High electrical consumption. Sensitive to particulate resistivity.

[a] Costs are first quarter 1980 dollars.

are collected in dry form, venturi scrubbers generate a wet slurry which is more voluminous and generally more difficult to dispose of. Unit installed costs for venturi scrubbers are approximately \$250/m^3/min.

Electrostatic precipitators are high efficiency particulate removal devices, have low pressure drops, are capable of handling large volumes of gases, and can tolerate high feed-gas temperatures. Electrostatic precipitators, however, are not generally suitable for applications to gases above atmospheric pressure and are not economical for treating small or intermittent gas flows (such as those resulting from material handling dust collection systems). Unit installed costs range from \$250 to \$530/m^3/min.

4.1.4.1 Boiler Flue Gases

Steam requirements for gasification, process heating, and power generation depend on the feed coal type, synthesis route and final products, types of mechanical drivers employed, the extent of energy self sufficiency, and several other site- and design-specific factors. Self sufficient facilities are reported to have boiler heat input requirements amounting to 15 to 30 percent of energy input to the gasifier. Most Lurgi facilities are expected to burn coal along with some or all of the gasification byproducts to meet boiler needs.

For purposes of developing example cost estimates for boiler flue gas controls, a specific case of methanol synthesis with Rosebud coal is examined. Total boiler input is estimated at 1490 GJ/hr (HHV), and about 40% of this can be met by firing Lurgi tars, oils, phenols, and naphtha. Table 4-17 summarizes the amounts of coal and byproducts used as boiler feed in this example along with the percent of heat input and fuel sulfur, nitrogen, and ash contributed by each material. About 22,000 kmols/hr of flue gas are generated from this fuel mix containing 760 ppmv SO_2, 280 ppmv NO_x, 8 grams/m^3 of particulate, and less than 100 ppmv each of CO and VOC.

The quantity of flue gas from combustion on site varies directly with the boiler duty and, to a much lesser extent, the fuel mix. The quantities of SO_2, NO_x, and particulate will vary both with type of coal and fuel mix. The types of controls applicable to boilers in the subject facilities are not influenced by the exact boiler size or by fuel mix. Of course, where fuel mix is such that the desired level of control for SO_2, NO_x, or particulate can be met without add-on processes, such processes might be considered as "not applicable." For analysis purposes it is assumed that some portion of the boiler duty will be met by firing coal; therefore, it may be desirable to control SO_2, NO_x, and particulates at the subject facilities.

TABLE 4-17. EXAMPLE BOILER FEED AND POTENTIAL EMISSIONS CONTRIBUTIONS[a]

Feed to Boiler	Feed Rate (Mg/hr)	Input Heat (%)	Input S (%)	Input Ash (%)	Input N (%)
Coal	44.3	59.6	84.0	90.8	84.1
Lurgi Tar	6.1	15.4	2.8	9.0	7.8
Lurgi Oil	6.2	16.5	5.4	0.3	6.5
Lurgi Naphtha	2.15	2.3	7.9	<0.01	1.6
Lurgi Phenol	1.05	6.3	<0.01	<0.01	<0.01
Total Inputs		1487 GJ/hr	0.58 Mg/hr	4.7 Mg/hr	0.47 Mg/hr

[a] Rosebud coal.

NO_x Control

As discussed previously, NO_x control in boilers is achieved through both the design and operation of the combustion units to minimize its formation. For new pulverized coal-fired boilers this is achieved primarily by the use of low NO_x burners. Boiler manufacturers have used low NO_x burners as standard equipment on new boilers since the early 1970s. Therefore, there are no incremental costs for NO_x control equipment since no new boilers can be purchased from U.S. manufacturers with alternative burners, regardless of whether the boiler is being built in the U.S. or abroad. However, retrofitting NO_x control equipment on older boilers does have cost implications. Their cost should be site specific and will also depend upon the type of NO_x control technique utilized. Since new facilities will employ new boiler units, retrofit costs for NO_x controls are not discussed in this document. However, these costs can be attained from several EPA documents (56,57).

Particulate Control

Particulate loading in boiler flue gases is a function of the type of fuel being fired, the amount of ash in the fuel, and, to a lesser extent, sulfur content of the fuel. For the Rosebud coal case under consideration, the uncontrolled particulate emission rate for the methanol synthesis case is estimated to be 4200 kg/hr.

Usually electrostaic precipitators or baghouses are used for particulate emission control from coal-fired boilers. The use of these technolgcies has served dust control purposes as well as operational requirements for SO_2 control equipment employed downstream of these units. Although in utility applications at present electrostatic precipitators are more widely used than baghouses, the trend in new installations is towards use of baghouses.

Costs for ESPs are based upon the ESP effluent particulate loading desired and the flue gas flow rate. To bracket emission levels commonly achieved, emissions corresponding to fossil-fuel-fired steam generator standards and electric utility steam generator standards were used as a basis for costing. Table 4-18 summarizes the controlled particulate emissions and estimated costs for particulate control. With a control efficiency of 99.6%, the estimated capital investment of $8 million and annualized cost of $12 million are 1.0 and 0.85% of the respective total base plant costs.

It should be noted that this 99% reduction of particulates emissions in the flue gas results in the collection of some 4200 kg/hr of dry solids. Handling this dry solid can result in fugitive particulate emissions. Control of such emissions are discussed in Section 4.1.6 under fugitive particulate emissions from materials handling.

TABLE 4-18. CONTROL OF PARTICULATES IN BOILER FLUE GAS BY ESP (ROSEBUD-METHANOL SYNTHESIS CASE)

	99.6% Control	98.6% Control
Controlled Particulate Emissions (kg/hr)	19	60
Costs[a]		
Total Capital	8.2	6.8
Total Annual Operating	0.2	0.2
Total Annualized	1.7	1.3
Percent of Base Plant		
Capital	1.0	0.83
Annualized	0.85	0.63

[a] Cost are millions of first quarter 1980 dollars.

SO_2 Removal

As discussed previously, a number of competitive FGD processes are capable of achieving similar SO_2 reductions from flue gases. However, Wellman-Lord and limestone FGD processes are the most widely used in industry today. The Wellman-Lord has been chosen to represent costs typical of non-throwaway FGD processes. These FGD costs have significant dependence on boiler size, fuel sulfur, and the degree of SO_2 removal desired. When sludge disposal costs are included, throwaway SO_2 removal processes incur costs similar to Wellman-Lord in similar service.

The boiler associated with a Lurgi methanol plant using Rosebud coal has approximately 16.5 kmol/hr (760 ppmv) of SO_2 in the flue gas. For cost analysis purposes, SO_2 reductions corresponding to 90 percent removal, the standards of performance for fossil-fuel-fired boilers (520 ng/J or 28 percent removal in this example), and the standards of performance for large electric utility steam generators (70 percent removal in this example) have been used. Table 4-19 presents the cost estimates for these levels of SO_2 control.

Secondary wastes from FGD systems include sludges, brines, and elemental sulfur. For the Wellman-Lord case about 130 kg/hr of brine is generated. Byproduct sulfur production of up to 330 kg/hr is also generated in the Wellman-Lord case.

TABLE 4-19. COSTS FOR WELLMAN-LORD CONTROL OF SO_2 IN BOILER FLUE GASES - ROSEBUD COAL TO METHANOL

	SO_2 Removal (percent)		
	90	70	28
Costs [a]			
Capital	38.7	34.3	23.7
Operating	7.3	5.8	2.9
Total Annualized	13.9	11.7	7.0
Percent of Base Plant			
Capital	2.9	4.2	2.9
Annualized	3.5	5.9	3.5
SO_2 Emissions After Control (kmols/hr)	1.7	5.0	12.0

[a] Costs are millions of first quarter 1980 dollars.

4.1.4.2 Process Heater Flue Gases

Process heaters in a coal gasification facility are expected to utilize either waste gases or liquid products from synthesis/fractionation operations. These waste gases and liquid fuels are essentially sulfur and nitrogen free. Therefore, the contribution of process heaters to sulfur and particulate emissions is minimal. Any NO_x emissions generated are a function of combustion design, and combustion modification techniques discussed previously are applicable.

Coal lockhopper gases may also be used as fuels in Lurgi-based plants and controls for these gases have been discussed in Section 4.1.2.1. If controls for SO_2 or particulates were desired, lockhopper gases would be used only in large boilers where controls should already exist rather than in small process heaters which would require add-on devices.

Control of NO_x emissions from process heaters has been investigated in recent years. Initial data indicate that low excess air, staged combustion, and low NO_x burners can be used to reduce NO_x emissions. Costs and effectiveness of these techniques are very site-, size-, and fuel-specific. The number and size of process heaters for a coal gasification facility depend upon the auxiliary configuration chosen. Since it is beyond the scope of this document to perform the detailed engineering required to assess all the possible configurations, no detailed cost estimates for the control of NO_x emissions from specific process heaters was performed. However, cost information from vendors indicates that low NO_x burners may cost approximately $0.95/MJ when applied to process heaters (59).

4.1.4.3 Wastewater Incineration Flue Gases

One approach to wastewater treatment in Lurgi facilities is incineration of preconcentrated wastes to destroy organics. Lurgi byproduct tars, oils, phenols, or naphtha could serve as convenient fuels. Flue gases from wastewater incineration will contain the inorganic salts present in the wastewater and SO_2 derived from sulfur in the fuel. NO_x is not expected to present problems since combustion temperatures are low. Some fixed nitrogen will be present in both the waste to be incinerated and the fuel and could contribute to fuel NO_x. Flue gas flow rates are estimated at 3400-7300 kmols/hr containing 0.02-0.1% SO_2 and 4-5 grams/Nm^3 particulate.

Venturi scrubbing is the most applicable control for particulate removal from high moisture flue gases. Scrubbing liquor will solubilize salts originally contained in the wastewater, and a blowdown for these salts from the system is required. Any particulate matter generated by fuel combustion (i.e., ash and carbon) will also be largely removed by venturi scrubbing so that suspended solids removal from scrubbing liquor blowdown should also be necessary. Venturi scrubbers can remove over 99% of particulate in flue gases, but in the subject application, 90-99% removal is probably more realistic.

If SO_2 removal is required, a captive FGD unit could be added to the venturi scrubber. Alternatively, caustic soda could be added to the venturi scrubbing liquor to effect SO_2 removal. Sodium sulfate/sulfite would be removed as blowdown from the system along with wastewater-derived salts.

Table 4-20 summarizes the estimated costs for the above controls. The calculations indicate that either Wellman-Lord or caustic addition for SO_2 control greatly add to the annualized cost of venturi scrubbing alone for particulate control. Control costs are also compared to base plant costs in Table 4-20. The capital and annualized costs range from 0.04 to 0.07% and 0.07 to 1.5%, respectively, of base plant costs based on control alternatives selected. In all cases, an aqueous brine is generated which would require disposal or further treatment.

TABLE 4-20. COST SUMMARY OF WASTEWATER INCINERATOR FLUE GAS CONTROLS

Control Technique	Estimated Control Costs[a]				
	Total Capital	Total Annual Operating	Total Annualized	Percent of Base Plant Costs Capital	Percent of Base Plant Costs Total Annualized
Low Pressure Venturi					
Venturi Only	0.33-0.56	0.07-0.13	0.13-0.23	0.04-0.07	0.07-0.12
With Wellman-Lord	4.01-6.24	0.62-0.87	1.31-1.94	0.49-0.76	0.66-0.97
Alkaline Scrubber	0.35-0.60	1.33-2.49	1.39-2.95	0.04-0.07	0.70-1.48
High Pressure Venturi					
Venturi Only	0.34-0.66	0.12-0.22	0.18-0.33	0.04-0.08	0.09-0.17
With Wellman-Lord	4.38-6.34	0.67-0.96	1.42-2.06	0.53-0.77	0.71-1.03
Alkaline Scrubber	0.36-0.71	1.38-2.94	1.44-3.05	0.04-0.09	0.73-1.53

[a] Costs are millions of first quarter 1980 dollars.

4.1.5 Fugitive Dust from Material Storage

Open or partially enclosed storage piles are often used for bulk materials not affected by precipitation or slight contamination such as coal, sand, gravel, clay, and gypsum. The material may be stored for a short time with a high turnover rate to accommodate surges in daily or weekly rates of sequential processes or may provide a long-term reserve for emergency supply or to meet cyclical seasonal demands.

Most dust arises from stockpile areas as the material is dumped from the conveyor or chute onto the pile and as material is removed from the pile. During periods of high wind speeds or low moisture, wind erosion of the surface may also cause emissions.

In coal gasification/liquefaction plants, fugitive dust emissions are emitted from coal and solid waste storage piles. The techniques used to control these emissions are not unique to coal gasification plants and are widely used in industries that require large scale materials storage. The most commonly used techniques are vegetative stabilization, chemical stabilization, capping, stacked segregation, water spraying, and confinement. Surface protection methods such as vegetative stabilization, chemical stabilizaton, capping, and stacked segregation are primarily used on reserve (inactive) storage piles since these piles are subject to minimal disturbances. Active storage piles generally require either water spraying or confinement to control dust emissions. The key features and unit costs for these techniques are listed in Table 4-21.

Vegetative stabilization involves planting an appropriate ground cover or shrub over the pile to be stabilized. A soil cap may be required to support vegetation. The efficiency of vegetative cover in reducing wind erosion is dependent on the density and type of vegetation that can be grown. For

TABLE 4-21. KEY FEATURES OF STORAGE PILE DUST CONTROL TECHNOLOGIES

Method	Control Principle	Control Effectiveness	Reliability/ Special Problems	Unit Costs[a]	Other Pollutants Generated
Vegetative Stabilization	Covering pile with sod.	Approximately 65% reduction over unstabilized pile; and 90% if chemical stabilizer is also used.	1. Requires frequent watering. 2. Handling of sod during reclamation operations is cumbersome and expensive. 3. Upper layer of stored material is contaminated with soil.	$2.70/m²	Soil dust from earth covering.
Chemical	Wetting Agents Modify surface tension properties to improve effectiveness of water sprays.	Up to 90% reduction in dust losses.	1. Piping may require heat tracing when freezing is a concern. 2. Can cause corrosion problems in equipment exposed to sprays. 3. May increase material degradation.	$.33-.77/Mg	Volatiles which depend on wetting agent utilized.
	Crusting Agents Organic binders combine with particles to form tough crust on surface.	Up to 90% reduction in dust losses.	1. May increase chances of spontaneous combustion, especially in piles subject to stockpile and reclaim operations. 2. Crust tends to break up during heavy rains.	$.55-.22/m²	Volatiles which depend on crusting agent utilized.
Capping	Paving with earth or asphalt or cover with polyethylene.	Up to 100%.	1. Both coverings may increase chances of spontaneous combustion. 2. Polyethylene presents severe handling problems and is also not practical in high wind climates.	$.49/m² for asphalt. $1.96/m² for polyethylene.	Soil dust from earth covering.

(Continued)

TABLE 4-21. (Continued)

Method	Control Principle	Control Effectiveness	Reliability/ Special Problems	Unit Costs[a]	Other Pollutants Generated
Stacked Segregation	Coating surface or compacted storage pile with layer of select, medium sized materials.	No data available.	Either deliveries of different sized material must be coordinated or both sizes must be readily available from storage.	Not available	None
Water Spray	Spray application of 210-150 L/Mg to reduce dusting.	Approximately 50% reduction in losses.	1. Piping may require heat tracing when freezing is a concern. 2. May increase degradation. 3. Frequent re-treatment necessary.	Not available	None
Confinement	Enclosure of active storage pile in a totally enclosed barn or silo with point source dust control equipment on building vents.	Up to 99% reduction in losses.	Requires extreme care when storing potentially explosive materials.	$110/Mg of stored material $1 million to $3 million per silo depending on size.	None

[a] Costs are first quarter 1980 dollars.

applications such as stabilizing tailing piles, the use of vegetative stabilization results in a decrease in emissions of approximately 65%. When vegetative stabilization is used in conjunction with a chemical stabilizer, this efficiency increases to approximately 90%.

Chemical stabilization to decrease fugitive dust emissions involves the application of wetting or crusting agents. Wetting agents are used to provide better wetting of fines and longer retention of moisture. They also reduce the water's surface tension allowing the fines to be wetted with a minimum amount of water. This treatment protects stockpiled material until the added moisture is removed by heat and wind. Some of these agents remain effective for weeks or months without additional rewatering, depending on local conditions. Crusting procedures involve the use of bunker C crude oil, water soluble acrylic polymers, or organic binders. These materials are sprayed on the surface of the storage pile, coating the top layer of particles with a thin film. This film causes the particles to adhere to one another to form a tough durable crust which is resistant to wind and rain. As long as the crust retains intact, the storage pile is protected from wind losses.

Capping involves the paving of the surface area of the storage pile with asphaltic compounds or earth or covering the pile with polyethylene tarpaulins. Usually a slurry of wood pulp and asphalt or road tar is sprayed over the surface of the pile. The covering is usually about 3 mm thick. Polyethylene tarpaulins are also used; however, they are cumbersome to handle when there are high wind speeds or when a large size storage pile is to be capped.

Another effective means of controlling dust emissions from coal storage piles is the stacking of coarse material on the surface of a properly compacted pile. For instance, a 0.152 m layer of fine coal (6.4 mm x 0 mm) on the top and sides of the coal storage pile can be anchored in place by a

0.102 m layer of larger size coal (24 mm x 0 mm) placed on top of the fine coal. The larger size coal has better weathering characteristics compared to the smaller sized coal.

Water spraying is another commom method of dust suppression. Dust control by water spraying is usually obtained by placing spray nozzles at strategic locations over the stockpile area. The spraying operation is simple in that it only involves the operation of a pump. Water requirements for large volume operations vary from 0.21 to 0.25 m^3/Mg of material. Such systems are, however, prone to freezeups during winter months. Also, the added moisture can create handling problems during reclamation and subsequent processing.

Enclosure of the coal storage pile is generally the most effective means of reducing fugitive dust emissions, because it allows the emissions to be captured. However, enclosures can be very expensive, since they have to be designed to withstand wind and snow loads and meet requirements for interior working conditions. An alternative to enclosure of all material is screening the material prior to storage, and sending the oversize material to open storage and the fines to enclosures.

4.1.6 Particulates from Material Conveying and Processing

Material transfer and conveying operations are common to nearly all processing industries. Equipment includes belt conveyers, screw conveyers, basket elevators, vibrating conveyors, and pneumatic conveyors. The type of conveying equipment varies with the application and is determined primarily by the quantity and characteristics (size, specific gravity, moisture content, etc.) of the material being handled, the transfer distance and elevation, and conditions of the working environment. Loss of material from conveyors is primarily at the feeding, transfer, and discharge points and occurs due to spillage or windage. The majority of particulate emissions are generally from spillage and mechanical agitation of the material at transfer points.

Material from storage piles is generally crushed, screened, and pulverized prior to transfer to the boiler or gasification plants. Fugitive dust generated during this process is typically controlled by either wet suppression techniques or dry particulate collection systems.

Fugitive particulate control systems utilizing a wetting agent consist of pre-engineered modules which incorporate both water handling components and automatic spray controls. A typical spray solution contains 1,000 to 4,000 parts of water to one part of a wetting agent. The rate of spray application is about 4 to 8 liters/Mg of material. This rate of application results in an increase of total surface moisture by about 0.5 to 1.0%.

In wet dust suppression, the fugitive particulate is first confined by a curtain of moisture droplets. Then the wetting of dust takes place by contact and penetration with moisture droplets. Finally, agglomerates are formed by contact with other droplets and settling takes place because of the additional weight of the other droplets. Wet suppression techniques can cost from $0.33 to $0.77/Mg of material processed, depending on the wetting agent utilized.

Dry particulate collection systems consist of enclosures to contain the particulates, ductwork and exhaust systems to convey the particulate laden air, and particulate collectors to separate the particulate from the discharge air. Typically, hoods are used to capture particulate emissions at transfer points. Conveyors generally have a half cover which provides dust containment and also shields the conveyor from wind, rain, and snow. Enclosure sizing is a function of the source under consideration. The type of enclosure used depends upon the particulate source. Typical ductwork velocities for particulate capture for different source types are readily available (60). Dust collectors that are applicble to the collection of the captured particulates are: 1) venturi scrubbers, 2) electrostatic precipitators, 3) fabric filters, and 4) dry centrifugal collectors. These have been discussed previously in Section 4.1.4.

4.1.7 Fugitive VOC Emissions

There are many sources of fugitive VOC emissions in a synthetic fuel plant. These emissions can be categorized as 1) evaporative emissions that result from the storage of liquid products and byproducts and 2) VOC emissions that result from fluid leaks from plant equipment.

Evaporative Emissions

Evaporative emissions from storage tanks storing volatile liquids occur because of temperature change which causes the vapor pressure of the stored liquids to vary, resulting in vapor emissions. The minimal accepted standard for storage of VOC is the fixed roof tank. It is designed to operate at only slight internal pressure or vacuum and is susceptible to emissions from thermal expansion and other mechanisms by which vapors are produced.

Emissions from fixed roof tanks can be reduced by minimizing diurnal temperature variations (e.g., placing tanks underground), proper setting and maintenance of pressure/vacuum vents, and leak prevention efforts. Significant controls can be effected by either floating a cover on the surface of the stored liquid or by replacing the fixed roof storage tank by a floating roof storage tank.

Floating roof tanks successfully limit hydrocarbon losses by eliminating the ullage into which stored material vaporizes. This is accomplished by floating a rigid deck or roof on the surface of the stored liquid, thus eliminating air space and preventing the formation of organic vapor above the liquid surface. To effectively control emissions, the floating roof employs primary and secondary seals to shelter the liquid surface from the atmosphere. Control efficiencies of greater than 90% are achievable by floating roof tanks.

Vapor processing units can also be used to control VOC emissions from fixed roof storage tanks. Some of the vapor processing techniques available and primarily demonstrated for gasoline usage are carbon adsorption, thermal oxidation, refrigeration, compression-refrigeration-absorption, and compression-refrigeration-condensation.

The carbon adsorption vapor recovery unit uses beds of activated carbon to remove VOCs from the air-vapor mixture. These units generally consist of two vertically positioned carbon beds and a carbon regeneration system. Air-vapor mixture enters the base of one of the adsorption columns and the VOC components are adsorbed onto the activated carbon as the gases ascend. Adsorption in one carbon bed occurs for a specific timed cycle before switch-over to desorption. The nearly saturated carbon bed is then subjected to vacuum, steam, or thermal regeneration or a combination of these methods, and the VOCs are stripped from the bed. Vacuum regenerated units recover VOCs by absorption in a cooled liquid stream which circulates between the control unit and product storage. The air and any remaining VOCs exiting from the absorber are passed again through the absorbing bed and exhausted to the atmosphere. Steam regenerated units condense the VOC-water mixture and return the separated product to storage. Some vacuum regenerated systems remain in operation for up to two hours after loading activity ceases, in order to collect any residual vapors in the system and to assure complete regeneration of the carbon beds.

Thermal oxidation units rely upon burning VOC vapors to produce nonpolluting combustion products. Vapors are piped either to a vapor holder or directly to the oxidizer unit. When a vapor holder is used, operation of the oxidizer begins or ends when the holder reaches the respective preset levels. With no vapor holder in the system, the oxidizer is energized by means of pressure in the vapor line or by an electrical signal produced by manual activation. In some cases, propane is injected into the vapor stream to keep the VOC level above the explosive range.

Refrigeration type recovery units remove VOCs from an air-vapor mixture by straight refrigeration at atmospheric pressure. Vapors displaced from storage tanks enter a condenser section where the temperature ranges from 190 K to 210 K. Some units contain a precooler section at 274 K to remove most of the water from the gases prior to the main condenser. There are no compression stages in this type of unit. The condensed product is collected and piped to one of the product storage tanks. The cold collection surfaces are periodically defrosted by pumping warm (305 K) liquid through the condenser. This defrost fluid is kept warm by heat salvaged from the refrigeration equipment. Recovered water can pass to a waste storage tank or an oil-water separator if the combination is not miscible. The defrost cycle takes from 15 to 60 minutes, depending on the amount of ice accumulated on the finned-tubes.

In a compression-refrigeration-absorption (CRA) vapor recovery system, the vapors from the storage tanks are first passed through a saturator which sprays liquid product into the air-vapor gas stream. This ensures that the VOC concentration is above the explosive range. The saturated gas mixture is stored in a vapor holder until, at a preset level, it is released to the control unit. The vapor holder is usually a special tank containing a bladder with variable volume and constant pressure. A product storage tank with a lifter roof can also function in this capacity.

The first stage of CRA processing is a compression-refrigeration cycle in which water and heavy VOCs are compressed, cooled, and condensed. The uncondensed vapors move into a packed absorber column where they are contacted by chilled liquid product drawn from product storage and absorbed. The fresh product stream is used first in the saturator, then it passes through an economizing heat exchanger as it enters the absorber. The rich absorbent also passes through the heat exchanger before being pumped back to storage. The operation of the control system is intermittent, starting when the vapor holder is filled and stopping at its lower preset level. Cleaned gases are vented from the absorber column to the atmosphere.

A vapor recovery system employing a compression-refrigeration-condensation unit makes use of a vapor holder to store accumulated air-vapor mixture and a saturator for ensuring that the VOC concentration is above the explosive range. The unit is activated and begins processing vapors when the vapor holder has filled to a preset level. Incoming saturated air-vapor mixture is first compressed in a two-stage compressor with an intercooler. Condensate is withdrawn from the intercooler prior to compression in the second stage. The compressed vapors then pass through a refrigeration-condenser section where they are returned along with the intercooler condensate to the product storage tank. Cleaned gases are exhausted from the top of the condenser.

Costs for vapor processing units vary with the type of product and the product throughput. In the case of gasoline, capital investment costs for these units range from $152,000 to $270,000 for a gasoline throughput of 380 m^3/day. These costs increase by 15% when the gasoline throughput increases by 150%.

Costs for aluminum internal floaters range from approximately $4300 to $42,200 for storage tanks with diameters of 5 to 30 meters, respectively. Secondary seals are estimated to cost $75 per linear meter for internal floaters and $130 per linear meter for external floating roofs (61).

Fugitive Organic Emissions

There are many potential sources of fugitive organic emissions that result when process fluids leak from plant equipment in a typical gasification/liquefaction synthetic fuel plant. Some of these are: pumps, compressors, in-line process valves, pressure relief devices, open-ended valves, sampling connections, flanges, agitators, and cooling towers.

There are two basic methods which have been used to control fugitive organic emissions: 1) leak detection and repair methods, and 2) equipment specification. Leak detection methods include individual component surveys, area (walkthrough) surveys, and fixed point monitors. In an individual component survey each fugitive emission source (pump, valve, compressor, etc.) is checked for VOC leakage. The source may be checked for leakage by visual, audible, olfactory, soap bubble, or instrument techniques. Visual methods are particularly effective in locating liquid leaks. Escaping vapors from high-pressure leaks can be audibly detected, and leaks of odorous materials may be detected by smelling the odor. Perhaps the best method of identifying leaks of VOC from equipment components is by using portable detection instruments. By sampling and analyzing the air in close proximity to the leak the hydrocarbon concentration of the sampled air can be determined. The leak rate from the source can be estimated, since relationships exist between monitoring concentrations and mass emission rates.

An area survey requires the use of a portable hydrocarbon detector and a strip chart recorder. The procedure involves carrying the instrument within one meter of the upwind and downwind sides of process equipment and associated fugitive emission sources. An increase in observed concentration indicates leaking fugitive emission sources. The instrument is then used for an individual component survey in the suspected leak area.

Fixed point monitors are automatic hydrocarbon sampling and analysis instruments positioned at various locations in the process unit. The instruments may sample the ambient air intermittently or continuously. Elevated hydrocarbon concentrations indicate a leaking component. As in the walk-through method, an individual component survey is required to identify the specific leaking component in the area. For this method, the portable hydrocarbon detector is also required.

Reduction of fugitive emissions from the identified leaking components is effected by repair methods. In many cases, perfect repair will not be achieved; however, effective repair can substantially reduce emissions from the leaking component. Typical repair methods employed on the various components are listed in Table 4-22.

TABLE 4-22. REPAIR METHODS FOR FUGITIVE EMISSIONS REDUCTION

Component	Repair Method
Pumps and compressors	Tighten packing gland
Relief valves	Manual release of the valve may improve the set seal
In-line valves	Tighten packing gland; lubricate plug type valves; inject sealing fluid into process valves requiring repair
Flanges	Replace flange gaskets

The second method used to control fugitive emissions is by equipment specification. Typical equipment specifications are listed in Table 4-23.

TABLE 4-23. EQUIPMENT DESIGN/MODIFICATIONS FOR FUGITIVE HYDROCARBON EMISSIONS CONTROL

Pumps	- improve seal at the junction of moving shaft and stationary casing - use sealess pumps - use double mechanical seals - use closed vent systems around seal areas
Compressors	- improve seal at the junction of moving shaft and stationary casing - use double mechanical seals - use closed vent systems around seal areas
Pressure Relief Devices	- use rupture disks upstream from the safety/relief valve - use resilient seal or "o-ring" relief valves - use closed vent systems to transport valve discharge to control devices
Open-Ended Valves	- install a cap, plug, flange, or a second valve to the open end of the valve
In-Line Valves	- use diaphgragm and bellows seal type valves

Costs for repair methods will depend upon the complexity of the component undergoing repair. The major costs of maintenance and repair methods are labor related. In the case of equipment specifications, costs will depend upon the component being replaced. Typically, double mechanical seals cost $815/pump. Flush oil systems for double mechanical seals cost $1500/pump.

4.1.7.1 Product/Byproduct Storage Emissions

Various types of storage vessels are employed to store petrochemical products. The suitability of a specific tank design depends on the vapor pressure that the stored product exerts at ambient conditions and the storage desired. The floating roof tank is widely used for control of volatile organic compounds such as gasoline, when the true vapor pressure is in the range of 10 to 80 kPa at storage conditions. Low vapor pressure VOCs (<10 kPa) are stored in fixed roof tanks. Therefore, methanol and gasoline products would be stored in floating roof tanks, and diesel fuel and fuel oil in fixed roof tanks. Uncontrolled emissions estimates from these tanks have previously been discussed in Section 3.6.5.

Emissions from floating roof tanks consist primarily of standing storage losses and wetting losses. These losses are greatly reduced by the addition of secondary seals. The most widely used approach for VOC control is addition of secondary seals to existing floating roof tanks. The secondary seal is generally of a resilient fabric (e.g., loop seals) or a pliable material such as treated rubber. Its flexibility allows it to maintain contact in places where the shell might be out of round as well as in areas where rivet heads project from the shell wall. Upon descent of the roof, these seals wipe down the film left behind by the primary seal. These seals also reduce standing storage evaporative losses since they form a second seal above the vaporized product which has diffused past (or permeated through) the primary seal. Not only do they form a second barrier for the vapor, they also seal this vapor off from the effects of mixing air. As a result, secondary seals are effective control devices which, when used on floating roof tanks, can reduce overall emissions by as much as 98% (refer to Table 4-24).

TABLE 4-24. STORAGE TANK EMISSION ESTIMATES

Product	Tank Information			Process Types[a]	Vapor Pressure (kPa)	Mass Emission Rate (kg/yr)[b]		Control Efficiency (%)
	Roof Type	Capacity (m^3)	Diameter (m)			Uncontrolled	Controlled	
Mixed Alcohols	Float	1,415	12.2	F-T	15.4 5.1	6,092 2,075	2,350 760	61 63
Methanol	Float	42,930	61.0	M,G	15.4 5.1	30,500 10,400	11,760 3,810	61 63
Gasoline	Float	9,540	32.0	F-T	46.1 5.1	17,940 9,650	992 527	94 95
Gasoline	Float	14,310	35.1	G	46.1 24.1	19,660 10,580	1,100 591	94 94
Diesel	Fixed	1,590	13.1	F-T	0.08 0.023	386 98	25.8 25.3	93 74
Fuel Oil	Fixed	493	10.4	F-T	5.5×10^{-4} 1.48×10^{-4}	4.2 1.5	0.53 0.14	87 91
Lurgi Naphtha	Float	1,113	12.5	All	32.1 16.4	4,370 2,190	246 136	94 94
Lurgi Oil	Fixed	1,590	13.1	All	0.90 0.10	3,730 1,160	40.7 32.4	99 97
Lurgi Tar	Fixed	6,360	23.4	All	0.66 0.24	10,640 1,990	79.6 66.3	99 97
Lurgi Phenol	Fixed	1,113	12.5	All	0.79 0.124	2,430 480	31.2 22.8	99 95

[a] F-T = Fischer-Tropsch; M = Methanol; G = Mobil; M = Gasoline

[b] The higher values represent the month with maximum emissions from one of the study sites. The lower numbers represent the minimum average annual values from one of the study sites.

Fixed roof tanks consist of a steel cylindrical shell with a permanently-affixed roof. The roof design may vary from cone-shaped to flat. Of presently employed tank designs, the fixed roof tank is the least expensive to construct and is generally considered as the minimal accepted standard for storage of petroleum liquids. Fixed roof tank emissions are most readily controlled by the installation of internal floating roofs. An internal floating roof tank is essentially a fixed roof tank with a cover floating on the liquid surface inside the tank, rising and falling with the liquid level. Generally, emission reductions of more than 90% are achieved by retrofitting fixed roof tanks with internal floating roofs. Other control technologies such as vapor processing systems can also be used to effect 90% control. However, internal floating roof covers are widely used because of their simplicity and low annual operating and capital costs. Controlled emissions from fixed roof tanks are listed in Table 4-24.

Cost increments for the application of secondary seals or internal floaters to storage tanks at the subject facilities are listed in Table 4-25. The capital investment and net annualized costs per product produced in the subject facilities are estimated to range from $4,900 to $30,800 and from zero to $7,000, respectively. These costs are less than 0.004% of the respective base plant costs.

TABLE 4-25. ESTIMATED INCREMENTAL COSTS FOR STORAGE OF SYNTHETIC LIQUIDS[a]

Type of Liquid (tank size)	Type of Control[b]	Capital Investment (10^3\$)	Percent of Base Plant Costs	Annualized Control System Costs (Dollars)	Annual Product Savings (Dollars)	Net Annual Cost (Dollars)	Controlled Emissions Cost per kg (\$/kg)
Methanol (1,415 m^3)	SS	4.98	0.001	1,340	590	750	0.30
Metahnol (42,930 m^3)	SS	24.91	0.003	5,770	2,960	2,810	0.22
Gasoline (9,540 m^3)	SS	13.07	0.002	3,140	4,610	(1,470)[c]	0
Gasoline (14,310 m^3)	SS	14.34	0.002	3,420	5,050	(1,630)[c]	0
Diesel (1,590 m^3)	IF	14.74	0.002	3,400	41	3,350	20.2
Fuel Oil (493 m^3)	IF	10.99	0.001	2,550	0.41	2,550	981
Lurgi Naphtha (1,113 m^3)	SS	5.10	0.001	1,370	90	1,280	0.41
Lurgi Oil (1,590 m^3)	IF	14.74	0.002	3,400	120	3,180	0.03
Lurgi Tar (6,360 m^3)	IF	30.78	0.004	7,150	160	6,990	1.12
Lurgi Phenol (1,113 m^3)	IF	13.88	0.002	3,250	31	3,220	2.25

[a] Costs are first quarter 1980 dollars.
[b] SS - secondary seal, IF - internal floater.
[c] Credits.

4.1.7.2 Fugitive Organic Emissions from Process Equipment

As discussed earlier, process equipment such as pumps, compressors, in-line valves, pressure relief devices, open-ended valves, etc., are prone to leakage and thus are sources of fugitive organic emissions. Two methods can be employed to control these emissions. A labor intensive method involving leak detection and constant repair and maintenance can be used and/or replacement of leaking equipment by leak-free equipment can be applied. Obviously, if equipment specification, in addition to extensive leak detection and repair, is performed greater reduction in fugitive organic emissions is achieved.

Two approaches to reduce fugitive organic emissions are generally used. In the first approach, leak detection and repair methods presented in the VOC leak control techniques guideline document for the petroleum industry (62) can be applied. Here leak detection is accomplished by checking equipment components for emissions of VOC at specified intervals using a portable VOC detection instrument to sample and analyze the air in close proximity to the potential leak area. A measured VOC concentration greater than some predetermined level would then be a leak that would require equipment repair. A measured VOC concentration less than the detection level is assumed not to require any equipment repair. Inspection of all equipment has to be performed on a regular basis.

Using the aforementioned approach, controlled emissions were estimated for the subject facilities. Emission reductions of approximately 70% (see Control Technology Appendices for Pollution Control Technical Manuals for details of emission reduction calculations) were estimated for the three indirect liquefaction cases as shown in Table 4-26. For SNG production, no liquid products are synthesized and the uncontrolled fugitive VOC emissions from byproduct handling are less than those estimated for best control of

TABLE 4-26. FUGITIVE ORGANIC EMISSIONS FROM PROCESS EQUIPMENT

	Uncontrolled Emission Factor (kg/hr)	Uncontrolled Emission Rates (kg/hr)			Controlled Emission Rates (kg/hr)		
		Fischer-Tropsch	Methanol	Mobil-M	Fischer-Tropsch	Methanol	Mobil-M
Pump Seals [a]							
Light Liquid Service	0.113	18.0	4.4	8.3	0 - 4.5	0 - 1.1	0 - 2.1
Heavy Liquid Service	0.021	0.5	0.2	0.4	0 - 0.4	0 - 0.2	0 - 0.3
In-Line Valves							
Gas Service	0.027	37.0	9.9	18.0	5.7	1.0	1.8
Light Liquid Service	0.011	40.0	9.8	18.0	10.3	2.6	4.8
Heavy Liquid Service	0.00023	0.1	0.1	0.1	0.1	0.06	0.1
Safety Relief Valves							
Vapor Service	0.086	25.0	5.2	11.0	9.4	0 - 2.0	0 - 4.3
Compressor Seals [a]							
Hydrocarbon	0.64	13.0	2.9	1.5	0 - 3.8	0 - 0.8	0 - 0.5
Hydrogen	0.05	1.8	—	—	0.9	—	—
Flanges	0.00025	1.4	1.5	2.8	1.4	1.5	2.8
Drains	0.032	12.0	3.1	5.6	6.7	1.8	3.2
TOTALS		149	37.0	66.0	22 - 41	7.0 - 11	13 - 20

[a] Uncontrolled emission factors for each pump seal and compressor seal.

indirect liquefaction plants (compare Table 3-47). These estimates were based on a detection level of 10,000 ppm, weekly inspections of light liquid pump seals, monthly inspections of all other equipment, and sealing of open-ended values with a caplug or another valve.

Both capital investment and annualized costs are approximately $41,0000 for methanol synthesis which correspond to less than 0.01% and 0.02% of the respective base plant costs. Additional cost data are presented in Table 4-27.

The second approach goes a step beyond the first in that it relies on equipment specification in addition to leak detection, repair, and maintenance. Monitoring requirements are similar to those for the first approach, except in cases where equipment specification eliminates the need for monitoring. Typical equipment specifications can consist of caps for open-ended valves, rupture disks on gas service relief valves, and double mechanical seals with a seal oil flushing system on pumps. In addition, compressor seal areas and degassing vents from seal oil reservoirs, or both, can be connected to a control device with a closed vent system. As a result of these equipment specifications, fugitive emissions from pumps, safety/relief valves, compressors, and sampling connections can be completely controlled.

Application of these equipment specifications can reduce emissions by approximately 80% (See Control Technology Appendices for details) as shown in Table 4-26. As can be seen from Table 4-27, equipment specification costs are higher than that for inspection and repair. Capital investment costs are about 13 times greater and net annualized costs between 5 and 6 times greater with an additional 35 to 40% reduction in emissions.

TABLE 4-27. CAPITAL AND ANNUALIZED COSTS FOR FUGITIVE VOLATILE ORGANIC COMPOUND EMISSION CONTROLS

Control Technique	Estimated Control Costs[a]				
	Total Capital	Total Annual Operating[b]	Total Annualized[b]	Percent of Base Plant Costs Capital	Percent of Base Plant Costs Total Annualized
Fischer-Tropsch Cases					
Inspection/Repair	145	106	132	0.02	0.07
Equipment Specifications	2140	197	851	0.26	0.43
Methanol Cases					
Inspection/Repair	41	34	42	<0.01	0.02
Equipment Specifications	526	52	205	0.06	0.10
Mobile M Cases					
Inspection/Repair	70	21	34	<0.01	0.02
Equipment Specifications	916	(92)[c]	197	0.11	0.10

[a] Costs are thousands of first quarter 1980 dollars.
[b] Includes credit for recovered products.
[c] Net credit.

4.1.8 Air Pollution Control in Integrated Facilities

Processes for the control of specific air pollutants and specific streams have been examined in Sections 4.1.1 through 4.1.7. However, the overall effectiveness and costs of control cannot be assessed without an examination of integrated systems for management of gaseous waste streams. In this section, examples of sequential and combined control of waste streams are evaluated from the standpoint of the overall emissions reductions achieved and costs incurred. The selection of specific control examples for evaluation in this section is not intended to imply that other technologies could not provide equivalent or better performance with similar or even lower costs. Specific technologies are selected to cover the types of alternatives which have actually been proposed for facilities in the U.S. (63). Selection of integrated controls will be based upon specific design requirements and local conditions and can only be made by designers and permitting authorities involved in a specific project.

For evaluation of control alternatives of reduced sulfur compounds, volatile organic compounds (VOC), and CO, only the methanol synthesis cases with low sulfur (Dunn lignite) and high sulfur (Illinois No. 6) coals were examined. The F-T, Mobil M-gasoline, and SNG cases generally do not present new control options, but rather only small changes in the absolute volumes of gaseous waste streams (and hence absolute control costs). The two selected coal cases are sufficient to provide some insight into the impact of coal on control choices and on the cost and performance of integrated controls.

4.1.8.1 Example 1 - High Sulfur Coal/Selective Rectisol

Fundamental to the design of a Lurgi gasification plant is the mode of Rectisol operation. Although Rectisol units can be designed for selective operation with feed gases from coals having any level of sulfur, the economics are dramatically affected by coal sulfur level. Generally, selective Rectisol would become more economical in an integrated facility as the coal sulfur level increases, since it is the ratio of H_2S to CO_2 which determines cost in selective acid gas removal. CO_2 loading is only modestly dependent upon coal type, while H_2S loading is almost directly proportional to coal sulfur content.

Implicit in the choice of selective Rectisol is the use of Claus technology for bulk sulfur removal. Depending on the coal sulfur level and mode chosen for Claus operation (split flow vs. straight through; oxygen vs. air), hydrocarbon removal and/or H_2S enrichment using amine processes may be featured. As coal sulfur content increases, the sulfur level in the H_2S-rich fraction also increases while hydrocarbon levels remain essentially constant. With high sulfur coals and/or the use of oxygen in the Claus process, no H_2S enrichment or hydrocarbon removal may be necessary in order to process the waste gas in a "straight through" Claus unit.

Claus tail gases and amine offgases are treated using either incineration/SO_2 removal processes (Wellman-Lord) or catalytic processes (Beavon or SCOT). From the standpoint of overall sulfur emissions reduction, these processes are nearly equivalent. SCOT and Beavon tail gases may be incinerated for VOC and CO control. The smaller volume, sulfur containing waste gases from gas liquor separation and ammonia stripping/recovery are combined with H_2S-rich Rectisol (or amine) acid gases for amine processing. The small volume waste gases could alternatively be handled directly in Claus tail gas units, depending on the sulfur loading of the gases.

Figure 4-3 depicts the Example 1 flow scheme. Amine enrichment/hydrocarbon removal is included in this integrated example since the H_2S content of selective Rectisol acid gases is only 8% (this value is based upon data from a specific selective Rectisol plant at Kosovo). This value of 8% is

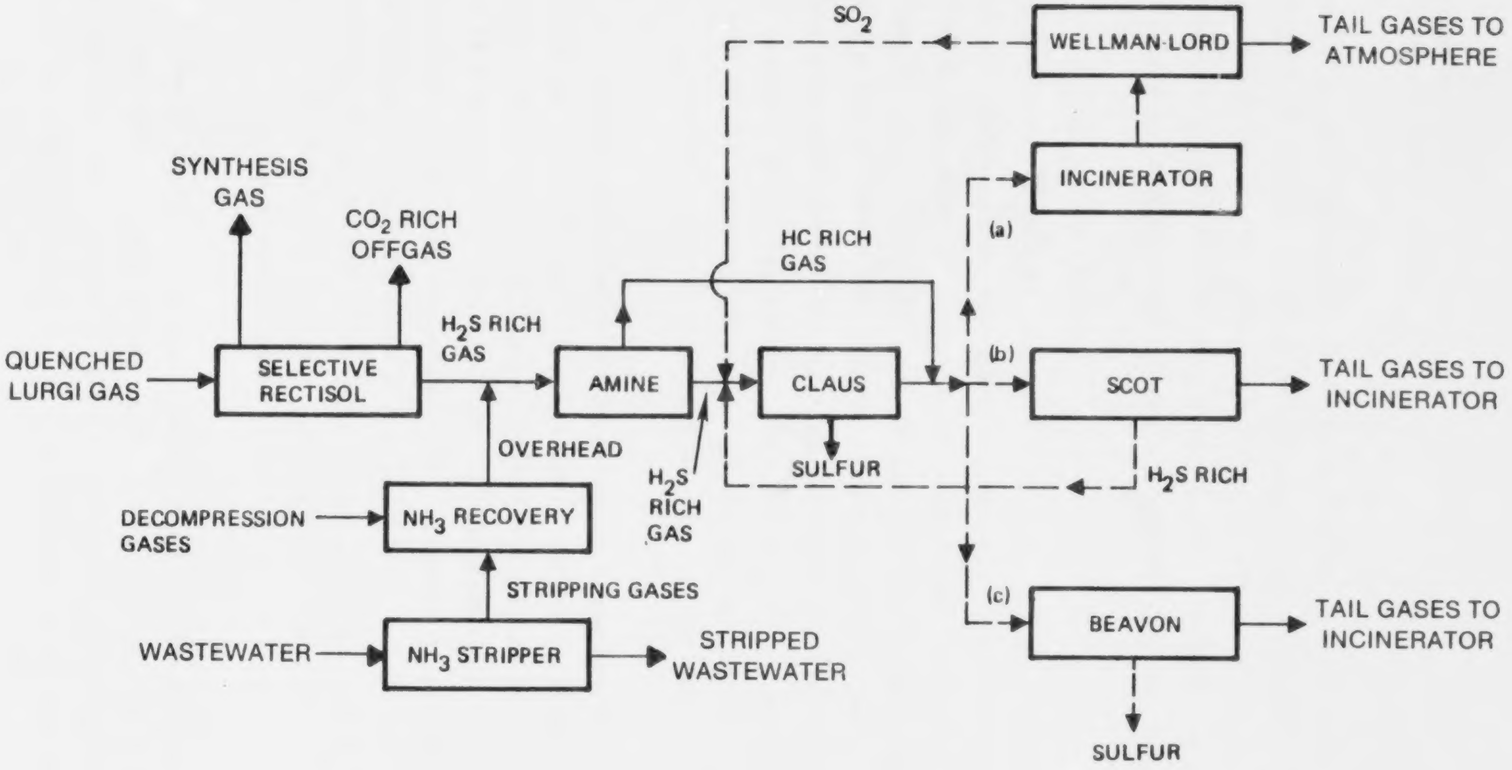

Figure 4-3. Schematic flow diagram for example 1 integrated control

believed to be very low relative to what can actually be obtained with modern selective Rectisol designs. Tables 4-28 through 4-31 present calculated mass flow data for Example 1. Over 99.5% control of potential sulfur emissions is achieved, which corresponds to emissions of 15 to 30 kg/hr sulfur in the form of SO_2. Over 99% control of both VOC and CO are also achieved corresponding to 20 kg/hr VOC and 60 kg/hr CO emissions to the atmosphere.

Estimated costs for the Example 1 controls are summarized in Table 4-32. These estimates indicate that amine enrichment can be an imporatnt cost factor in integrated control. Also, the relatively large contribution of tail gas treatment costs compared to Claus cost reflects the fact that amine offgases as well as Claus tail gases are handled by the tail gas treatment units. Only small differences in costs are seen in the estimates for SCOT and Beavon processes as might be expected for competing processes achieving similar control levels. Wellman-Lord is calculated to be more expensive than the catalytic processes. The three tail gas treatment processes have different impacts on the size and cost of the parent Claus plant. In the Beavon case, no recycle occurs so that the Claus unit is unaffected. In the SCOT case, H_2S is recycled so that the Claus plant has a 20% increase in sulfur load and a 50% increase in input flow. In the Wellman-Lord (W-L) case, SO_2 amounting to about 20% of the Claus feed is recycled, but unlike the SCOT case the feed gas flow is not greatly increased since no CO_2 recycles with the sulfur. Also compared to the SCOT case, Claus tail gas volume in the W-L case is not greatly increased since recycle of sulfur as SO_2 rather than H_2S reduces air requirements for the Claus plant. The Claus costs in Table 4-32 partially reflect the impact of these flow differences. A more detailed cost evaluation, would probably show total annualized costs of integrated Claus/W-L to be even closer to those of Claus/SCOT/incineration. In Example 1, 3.7 to 4.9% of the base plant capital cost and 2.7 to 3.4% of the base plant annualized costs are represented for the integrated control of Rectisol acid gases and smaller volume gases.

TABLE 4-28. MATERIAL FLOW FOR EXAMPLE 1 INTEGRATED CONTROL - AMINE ENRICHMENT OF RECTISOL AND STRIPPER OVERHEAD GASES[a,b]

	Selective				Amine Gases	
	CO_2-Rich Rectisol Gases	H_2S-Rich Rectisol Gases	NH_3 Stripper Overhead	Combined Acid Gas	HC-Rich	H_2S-Rich Claus Feed
H_2	37	4		4	4	
N_2+Ar	0.8	6		6	6	
CO	5	68	2.2	70.2	70.2	
CO_2	4196	1655	253	1908	1703	205
CH_4	14	26	7.3	33.3	30.1	3.17
Aliphatics	88	55	0.7	56	55.3	0.65
Aromatics	0.014	0.21		0.21	0.21	
H_2S	0.07	174.7	6.5	181.2	1.05	180.14
COS	0.3	1.9	0.023	1.92	1.69	0.23
Mercaptans		17.5	1.24	18.7	18.7	
HCN	0.04	0.19	0.35	0.54	0.003	0.54
NH_3	0.02		0.7	0.7	0.7	
CH_3OH	4.3	8.5		8.5	8.5	
Total Dry Gas	4345	2017	272	2289	1899	390
H_2O	0	0	114	114	91	23

[a] Methanol synthesis from Illinois #6 coal, selective Rectisol.

[b] Units are kmol/hr.

TABLE 4-29. MATERIAL FLOW FOR EXAMPLE 1 INTEGRATED CONTROL - SCOT TAIL GAS TREATMENT[a,b]

	Claus Feed Gas (Includes Recycle)	Claus Air	Claus Tail Gas	Claus Tail + Amine HC-Rich Gases	SCOT Gases Recycle Gas	SCOT Gases Tail Gas[c]	SCOT Condensate	Incinerated SCOT Tail Gas[d]	Sulfur Recovered
H_2				4		284			
O_2		113						56	
N_2+Ar		423	423	429		784		2050	
CO				70.2		277		1.3	
CO_2	410		412	2115	205	1910		2186	
CH_4	6.3		4.2	34.3	3.1				
Aliphatics	1.5		0.98	56.3	0.8			0.4	
Aromatics				0.21					
H_2S	215		6.5	7.4	35	0.65	<0.1		
COS	0.23		0.97	2.8		0.16			
CS_2			0.05	0.05					
SO_2			3.2	3.2				0.64	
Mercaptans				18.7					
HCN	0.54		0.36	0.36					
NH_3				0.7		0.1	1.0		
CH_3OH				8.5		8.5			
Total Dry Gas	633	536	851	2750	244	3264		4295	
H_2O	36		250	341	13	140	218	424	
Elemental Sulfur			4[e]	4[e]					200

[a] Methanol synthesis from Illinois #6 case, selective Rectisol, amine enriched.

[b] Units are kmol/hr.

[c] Excludes air (449 kmol/hr) added to partially oxidized hydrocarbons.

[d] 20% excess air, no additional fuel for incineration assumed.

[e] Entrained sulfur in Claus tail gas.

TABLE 4-30. MATERIAL FLOW FOR EXAMPLE 1 INTEGRATED CONTROL - BEAVON TAIL GAS TREATMENT[a,b]

	Claus Feed	Claus Air	Claus Tail Gas	Claus Tail Gas + Amine HC-Rich Gas	Beavon Tail Gas[c]	Sulfur Recovered	Incinerated Tail Gas[d]	Beavon Condensate
H_2				4	329			
O_2		93					63	
N_2+Ar		348	348	354	763		2192	
CO				70.2	304		1.4	
CO_2	205		206	1909	1909		2213	
CH_4	3.17		2.11	32.24				
Aliphatics	0.65		0.42	55.7			0.5	
Aromatics				0.21				
H_2S	180.14		5.41	6.46	0.03			<0.1
COS	0.23		0.81	2.50	0.23			
CS_2			0.05	0.05	0			
SO_2			2.71	2.71	0		0.25	
Mercaptans				18.7	0			
HCN	0.54		0.36	0.36				
NH_3				0.7	0.1			1.06
CH_3OH				8.5				
Total Dry Gas	390	441	566	2465	3306		4469	
H_2O	23		200	291	114		443	177
Sulfur			4[e]	4[e]		201[f]		

[a] Methanol synthesis from Illinois #6 coal, selective Rectisol, amine enriched.

[b] Units are kmol/hr.

[c] Excludes air (518 kmol/hr) added to partially oxidized hydrocarbons.

[d] 20% excess air.

[e] Sulfur entrained in Claus tail gas as S.

[f] as S.

TABLE 4-31. MATERIAL FLOW FOR EXAMPLE 1 INTEGRATED CONTROL - WELLMAN-LORD TAIL GAS TREATMENT[a,b]

	Claus Feed (with Recycle SO_2)	Claus Air	Claus Tail Gas	Claus Tail Gas + Amine HC-Rich Gas	Auxiliary Air[c]	Wellman-Lord Recycle SO_2	Tail Gas	Sulfur Recovered
H_2				4				
O_2		60			555		111	
N_2+Ar		225	225	231	2090		2321	
CO				70.2			1.3	
CO_2	205		205	1908			2211	
CH_4	3.17		2.49	32.6				
Aliphatics	0.65		0.5	55.8			0.46	
Aromatics				0.21				
H_2S	180.14		6.37	7.42				
COS	0.23		0.95	2.64				
CS_2			0.05	0.05				
SO_2	32		3.18	3.18		32	0.69	
Mercaptans				18.7				
HCN	0.54		0.42	0.42				
NH_3				0.7				
CH_3OH				8.5				
Total Dry Gas	422	284	444	2343	2645	32	4645	
H_2O	25		201	292			413	
Sulfur			2[d]	2[d]				200[e]

[a] Methanol synthesis from Illinois #6 coal, selective Rectisol-amine enriched.
[b] Units are kmol/hr.
[c] 20% excess air.
[d] Entrained and vaporous sulfur as S.
[e] as S.

TABLE 4-32. COSTS ASSOCIATED WITH EXAMPLE 1 INTEGRATED CONTROL[a]

	Case 1a Beavon/Stratford		Case 1b SCOT		Case 1c Wellman-Lord (W-L)	
	Capital	Operating	Capital	Operating	Capital	Operating
Hydrocarbon Removal/Sulfur Enrichment (Amine)	10.5	1.17	10.5	1.17	10.5	1.17
Bulk Sulfur Removal (Claus)	7.10	(0.72)	8.6[b]	(0.87)	7.8[b]	(0.79)
Tail Gas Treatment (Residual Sulfur)	11.9	1.92	11.8	1.63	21.7	0.21
Tail Gas Treatment (VOC, CO, and Reduced Sulfur)	1.00	(1.18)	1.00	(0.82)	0[c]	0[c]
TOTAL	30.5	1.19	31.9	1.11	40.0	0.59
Total Annualized Costs	6.44		6.60		7.47	
Percent of Base Plant Costs						
Capital	3.71		3.89		4.88	
Annualized	2.68		2.75		4.95	

[a] Costs are millions of first quarter 1980 dollars.

[b] Claus cost differences result from sulfur load and quantity of SCOT and W-L recycles to the parent Claus plant.

[c] No incremental costs for control of reduced species occur in W-L since incineration is implicit in W-L.

It should be noted that some portion of Rectisol costs in the selective mode might be assigned to pollution control. Data are not available relating to such costs, so it is not possible to estimate the specific incremental Rectisol contribution. The inclusion of costs for amine enrichment/hydrocarbon removal in Example 1 serves to indicate the magnitude of costs likely to be associated with generating high H_2S, low VOC Claus feed gases. In an integrated design there will always be a tradeoff between costs of enrichment within Rectisol, costs of enrichment with an amine system following Rectisol, and costs of larger or smaller Claus and tail gas treatment units.

In Example 1, H_2S-rich Rectisol acid gases are enriched to about 40% H_2S, and organics have been largely removed from Claus feed. With lower sulfur coals it would be more difficult to achieve such a high H_2S level. For straight through Claus mode, 35 to 40% H_2S is probably the lowest H_2S level consistent with stable combustion; below this level split flow mode or oxygen (or enriched air) firing would be necessary for flame stability. With the split flow mode, where only one-third of the Claus feed is burned, any hydrocarbon and mercaptans in the feed would lead to coke deposits on the Claus catalyst and to "grey" sulfur. Thus either the organics must be removed from the Claus feed or oxygen used instead of air allowing straight through operation with lower H_2S levels. There is an economic tradeoff between Claus plant capital costs vs. oxygen use costs which tends to become more important as H_2S levels in Claus feed decrease. Further, since oxygen use also reduces tail gas treatment capital costs, and since organics limit the use of split-flow Claus below about 35% H_2S, oxygen or enriched air offers several potential advantages. Rough calculations based on oxygen at $50/Mg and the Claus and TGT costs in Table 4-32 suggest that for H_2S-rich Rectisol acid gases having 20% or less H_2S, oxygen-fired Claus would be cost competitive with amine enrichment/organics removal plus air-fired Claus when incremental TGT costs are included. Although Claus units are not ordinarily fired with oxygen in existing applications, such Claus designs are considered commercially available and present no new developmental problems. The lack of existing oxygen fired units merely reflects the relative economics, especially when a dedicated oxygen plant would be required. In coal gasification facilities a large oxygen plant would already exist, and the incremental costs for producing additional oxygen or enriched air are small (about 2 to 7% additional oxygen production capacity would be needed, depending primarily on the coal sulfur content).

4.1.8.2 Example 2 - Low Sulfur Coal/Nonselective Rectisol

Most existing Lurgi gasification plants overseas as well as proposed Lurgi plants for the U.S. feature nonselective Rectisol acid gas removal. Example 2 is based upon this mode of Rectisol operation and includes H_2S removal by the Stretford process. Depressurization and stripping gases are combined with Rectisol gases for treatment in the Stretford unit. Stretford tail gases are incinerated with heat recovery for conversion of reduced sulfur species to SO_2 and oxidation of VOC and CO. Figure 4-4 depicts the flow scheme for Example 2.

The nonselective Rectisol/Stretford approach is generally most attractive for lower sulfur coals since the generation of acid gases with H_2S contents sufficient for economical Claus processing becomes more expensive as coal sulfur level decreases. The Stretford process removes only H_2S sulfur and hence COS and mercaptans contained in the Rectisol acid gases will be present in the Stretford tail and/or oxidizer vent gases. Since non-H_2S sulfur in Rectisol acid gases increases as coal sulfur increases, total sulfur in Stretford tail gases will increase with feed coal sulfur content.

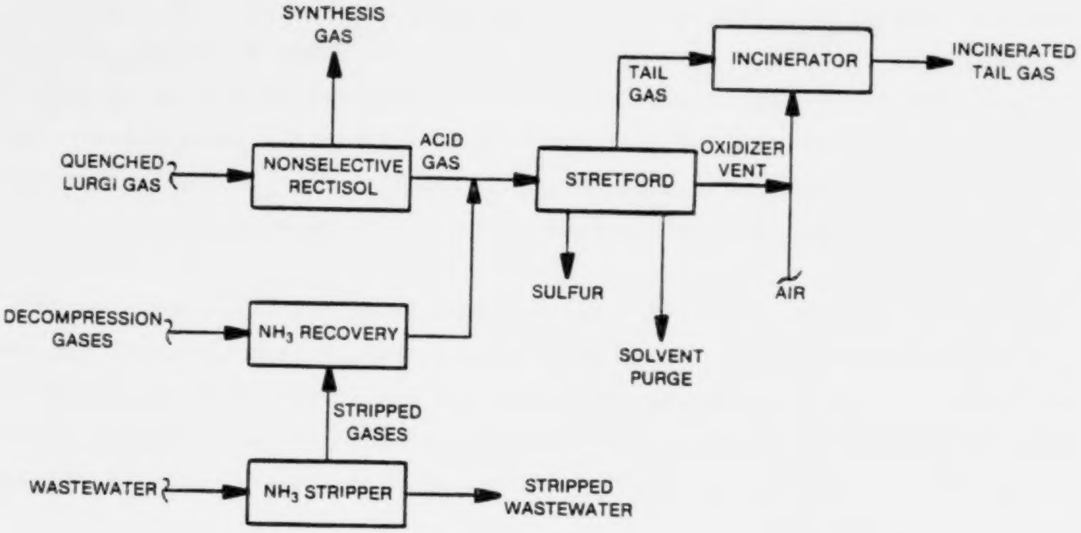

Figure 4-4. Schematic flow diagram for example 2

Table 4-33 presents calculated mass flows for Example 2. Stretford absorber vent gases contain about 1400 ppmv total sulfur and 2% VOC. Incineration of Stretford tail gases converts the COS and mercaptans to SO_2 and destroys most organics and CO. Since the tail gases represent a significant amount of energy, heat recovery is an attractive alternative. If a captive incinerator is used, heat exchange/steam generation could be an integral part of the design. Stretford gases can also be incinerated in boilers or steam superheaters, so that the energy value is recovered within those units. From the standpoint of control of reduced sulfur species, CO, and VOC, any of the incineration options are expected to achieve similar results.

Some of the mercaptans and ammonia contained in the Stretford feed gas may be found in the oxidizer vent gas. For control of these species, the vent gas can be used as supplemental combustion air for incineration of the absorber vent gases or for the boiler. Sufficient data are not currently available to indicate whether appreciable amounts of these species will be emitted in the Stretford oxidizer.

Table 4-34 summarizes the costs associated with Example 2 for a low sulfur coal. Specific costs attributable to incineration of Stretford tail gas can vary somewhat, depending on the extent of heat recovery and the dollar value of steam or direct heat assumed. In the table, the incremental costs of downrating a boiler which fires relatively low heating value Stretford tail gases are assigned to pollution control. A somewhat larger boiler incurs a slightly higher capital cost, while the recovered energy reduces operating costs by displacing overall fuel to the plant. A captive incinerator with 35% heat recovery appears to be about as cost effective for pollution control as a slightly larger boiler with 80% heat recovery.

TABLE 4-33. MATERIAL FLOW FOR EXAMPLE 2 INTEGRATED CONTROL - STRETFORD/INCINERATION[a,b]

	Acid Gas from Nonselective Rectisol	NH_3 Stripper Overhead Gas	Combined Acid Gas	Stretford Absorber Vent	Stretford Oxidizer Vent	Sulfur	Air Required	Total Oxidized Offgases[c]
H_2	25		25	25				
O_2					138		749	148
N_2+Ar	4		4	4	78.2		2818	3604
CO	43	1.6	44.6	44.6				3.2
CO_2	6274	210	6484	6397	87			6934
CH_4	54	5.3	59.3	59.3				
Aliphatics	123	2.4	125	125				1.1
Aromatics	0.7	1.7	2.4	2.4				
H_2S	74.3	2.1	76.4	0.67				
COS	0.64	0.017	0.66	0.66				
SO_2								9.37
Mercaptans	7.2	0.84	8.0	8.0	trace			
HCN	0.10	0.39	0.49		trace			
NH_3	0.18	0.39	0.57		0.57			<0.01
CH_3OH	8.6		8.6	8.6				
Total Dry Gas	6615	225	6839	6676	1008		3567	10700
H_2O	40	191	231	332	50			
Sulfur						75.7[d]	71	978

[a] SNG from Dunn lignite nonselective Rectisol.
[b] Units are kmol/hr.
[c] 20% excess oxygen, including oxidizer vent. No supplemental fuel assumed.
[d] As S.

TABLE 4-34. COSTS ASSOCIATED WITH EXAMPLE 2 CONTROL[a]

	Absorber Vent	Absorber Vent VOC and CO Control		Absorber Vent	Oxidizer Vent
	H_2S Control Only	Captive Incinerator	Use in Boiler	VOC, CO, and SO_2 Control Boiler + FGD	Incineration in Boiler
Gas Transport					
Capital	—	—	0.80	0.80	0.22
Annual Operating	—	—	0.10	0.10	0.01
Stretford					
Capital	14.9	14.9	14.9	14.9	—
Annual Operating	2.6	2.6	2.6	2.6	—
Incineration					
Capital	—	2.3	2.6	2.5	1.97
Annual Operating	—	0.39	0.01	0.01	0.02
FGD					
Capital	—	—	—	19	—
Annual Operating	—	—	—	4.5	—
Energy Penalty	—	(0.54)[b]	(4.4)	(4.4)	0.06
Total Capital	14.9	17.2	41.7	60.7	2.19
Total Annual Operating	2.6	2.45	(1.7)	2.7	0.08
Total Annualized	5.16	5.41	5.47	13.1	0.46
Percent of Base Plant Costs					
Capital	1.82	2.10	5.09	7.40	0.27
Total Annualized	2.40	2.52	2.54	6.09	0.21

[a] Costs are millions of first quarter 1980 dollars.

[b] ( ) indicates a credit.

In principle, Stretford tail gases could be treated for removal of additional sulfur, using the Beavon or FGD technologies. Technologies such as SCOT and Wellman-Lord are not applicable since they require Claus (or Claus type) plants to handle the produced H_2S (or SO_2). Since the economic and technical attractiveness of nonselective Rectisol/Stretford increases as coal sulfur contents decrease, Stretford tail gas would probably not exceed 1400 ppmv total S (the non-H_2S sulfur emissions in Example 2 have been taken as a worst case). While Beavon and FGD processes can handle such relatively dilute sulfur gases, their costs become very high, relative to the degree of further control achieved.

When Stretford tail gases are incinerated in boiler systems, the possibility does exist for combined SO_2 removal from boiler flue gases and incinerated Stretford tail gases. However, high incremental costs for FGD, compared to incineration only, are indicated by the calculations in Table 4-34. Further, captive boiler units in facilities gasifying the low sulfur coals most suited to Stretford acid gas treatment may not have FGD units, and hence the combined treatment option may not exist. Finally, the choice of nonselective Rectisol/Stretford/incineration versus selective Rectisol/Claus/tail gas treatment is primarily based on economics and an assessment of the overall reliability of the integrated system. If Stretford incineration alone cannot achieve sulfur levels consistent with source or ambient pollution control needs, it is likely that designers would opt for the selective Rectisol/Claus/TGT approach rather than add technologies such as Beavon or captive FGD to a basic Stretford unit.

The Beavon catalytic reactor was examined to assess whether it could precede the basic Stretford unit in an integrated facility, converting non-H_2S sulfur to H_2S and allowing very high levels of total sulfur removal. Such an arrangement is not feasible, however, since the catalyst performance is determined by the thermodynamics of the process which limits the degree of COS conversion at fixed CO_2 and H_2S levels. Without prior H_2S removal, a catalytic reactor might actually produce COS when CO_2 levels are in the 90% range. It is possible that most mercaptans would be hydrogenated over the catalyst, but total non-H_2S sulfur may not be greatly affected. Hence, catalytic conversion preceding Stretford is not likely to be a viable approach to reducing non-H_2S emissions in the subject facilities.

In Example 2, Stretford oxidizer vent gas is used as combustion air to an onsite boiler. The calculations in Table 4-34 indicate that costs for such an approach are in the same range as costs for incineration of absorber vent gases. Since the amounts of sulfur compounds and ammonia present in the oxidizer vent gases are not known, the cost effectiveness of control is impossible to evaluate.

4.1.8.3 Example 3 - Incineration of Waste Gases in Utility Boilers

Several gaseous streams in an integrated Lurgi-based facility contain organics and/or reduced sulfur and nitrogen species controllable by incineration. The energy value of many of these gases has drawn attention to heat recovery as part of the combustion step. Heat recovery is a common practice with gas incinerators; however, only minimal efficiency is attained when waste gases are burned in large boilers fired by coal, coal liquids, or fuel gases (over 85% recovery of LHV enthalpy of combustion is common in industrial boilers). Recovered heat partly offsets conventional fuel requirements to the plant, but increased capital cost are usually incurred. If a waste gas must be incinerated, there is always an economic tradeoff between capital cost of heat recovery equipment and the value of the energy recovered.

Figure 4-5 depicts integrated use of plant boiler/superheater system(s) to incinerate waste gases. High-pressure lock gases and startup transient gases have sufficient heating value to be considered fuels in their own right. For the intermittent waste gases, some storage would be necessary to lessen

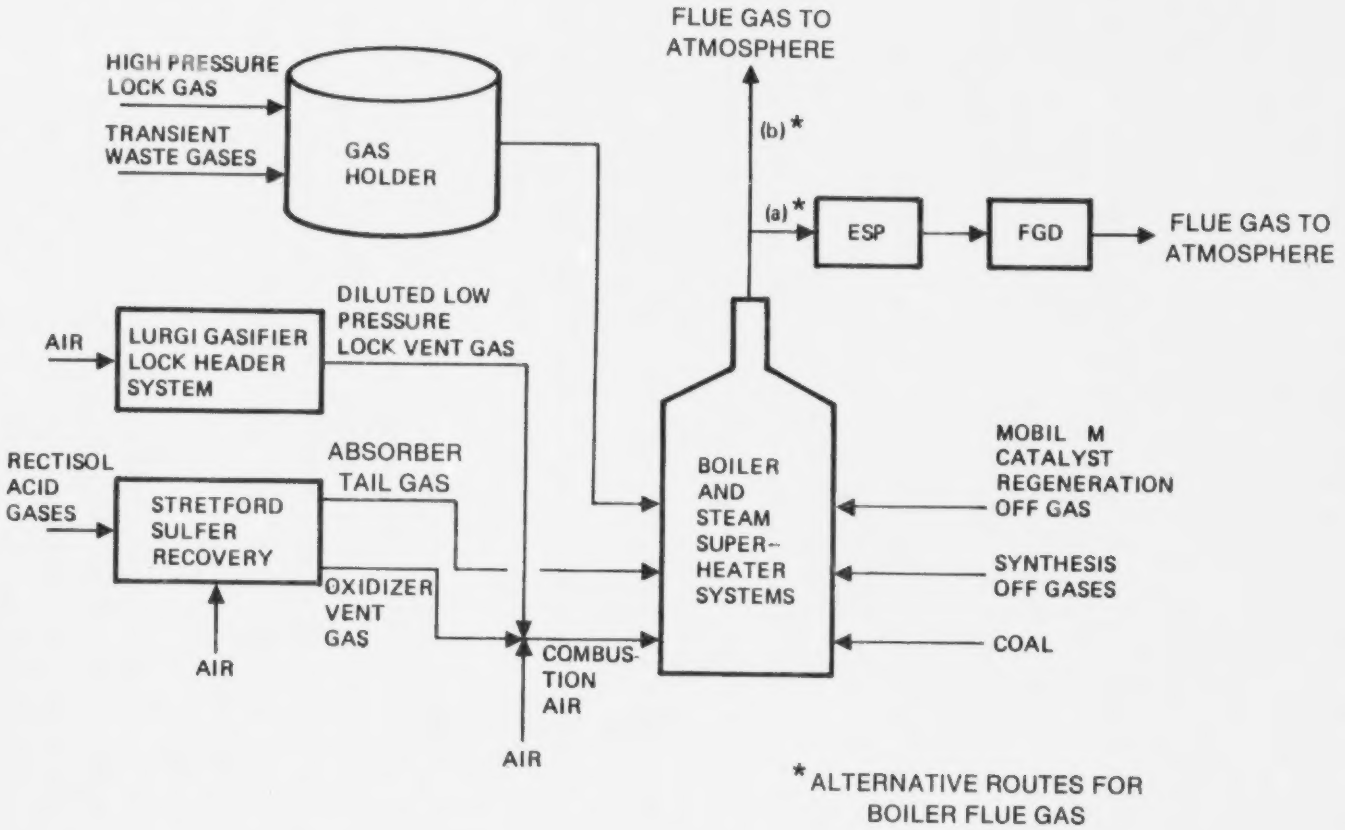

Figure 4-5. Example 3 - integrated control

surges and match production rates with boiler needs. Continuous, low heating value gases such as Stretford absorber vent gases may be difficult to incinerate alone due to flame stability problems, but they contain enough combustible components to justify their incineration in larger steam generation units.

Low-pressure (residual) coal lockhopper gases also have energy value but may contain ejection air. Such waste gases can supplement combustion air to large fuel using systems. Since dilution of lockhopper gases with at least 30/1 air would constitute prudent practice from an explosion hazard standpoint, combustion systems could draw a continuous air flow from the gasifier lock header system, thus diluting the gas to below explosive limits and achieving control when the diluted components pass through the combustion process. Since very little heating value is represented by the low pressure lockhopper gases, heat recovery is not a significant factor relative to the capital and operating costs of the collection and transport system.

Stretford oxidizer vent gases may contain low levels of odorous species and thus incineration is a likely alternative for odor control. The vent gas contains oxygen and could displace combustion air to the boiler. However, the lower O_2 content relative to air translates into an energy penalty in the boiler system. As with lock vent gas, collection/transport system costs will also be incurred.

The intermittent Mobil M-catalyst regeneration offgas may contain hydrocarbons and CO which could be controlled by incineration. Such gases could be incinerated in boiler systems rather than in a captive incinerator which would only operate intermittently.

The use of the boiler as an incinerator also offers the additional possibility of particulate and SO_2 control. When units such as ESPs and FGDs are captive to coal fired boilers, any waste gases incinerated in the boilers will pass through these units. Whether significant levels of dust and SO_2 removal are realized depends on the amounts of these constituents in the waste gas. Since ESPs and FGDs incur costs roughly proportional to flow rates, any waste gas producing more flue gas during combustion than an equivalent amount of coal (or other high grade fuel) on a heating value basis will necessitate larger pollution control units and capital costs.

The extent of overall control achieved with Example 3 is difficult to estimate. Generally, hydrocarbon and carbon monoxide levels in boiler flue gases are below 100 ppmv and 300 ppmv, respectively, but exact levels can vary widely. Such levels would correspond to over 90% control for all streams in Example 3, and over 99% control for high-pressure lockhopper gases and transient waste gases. If ESP/FGD systems are captive to the boiler, up to 90% control of potential SO_2 emissions could also be realized with boiler incineration. Since inorganic particulate is not a concern with the subject waste gases, the ESP does not serve a special purpose in Example 3, but rather is merely integral to coal fired boilers.

The estimated costs associated with Example 3 controls are summarized in Table 4-35. Since all of the subject gases except the intermittent Mobil M-catalyst regeneration offgases and the Stretford oxidizer vent gases contain combustibles (organics, CO, and H_2) of over 2% by volume, energy credits via heat recovery in the boiler are realized. Larger boiler and ESP/FGD systems are required, however, relative to coal-fired units having the same duty. Thus, an incremental capital cost is associated with use of the boiler as an incinerator. Additional capital and operating costs results from piping, fans, gas holding, and other handling/transport equipment.

TABLE 4-35. COSTS ASSOCIATED WITH EXAMPLE 3 INTEGRATED CONTROL

Control Technique	Estimated Control Costs[a]				
	Total Capital	Total Annual Operating	Total Annualized	Percent of Base Plant Costs	
				Capital	Total Annualized
H.P. Lock Gas					
VOC + CO Control	2.01	(3.35)[b]	(3.0)	0.25	Neg.
SO_2 Control	3.14	(3.28)	(2.7)	0.38	Neg.
L.P. Lock Gas					
VOC + CO Control	0.29	(0.024)	0.026	0.03	0.01
SO_2 Control	0.31	(0.024)	0.029	0.03	0.01
Stretford Absorber Vent					
VOC + CO Control	26.8	(4.3)	0.3	3.3	0.14
SO_2 Control	45.8	0.2	8.1	5.6	3.8
Stretford Oxidizer Vent					
VOC + CO Control	1.97	0.08	0.42	0.24	0.19
SO_2 Control	3.42	0.42	1.01	0.41	0.47
Mobil M-Catalyst Regeneration					
VOC + CO Control	0.4	0.02	0.09	0.04	0.04
Transient Waste Gas					
VOC + CO Control	10.2	0.002	1.76	1.2	0.88
SO_2 Control	17.3	1.3	4.27	2.1	2.1

[a] Costs are millions of first quarter 1980 dollars.
[b] ( ) indicates a net credit.

Neg. = Negative value.

The calculations in Table 4-35 indicate that the dollar value of the energy recovered from high-pressure lock gases can more than offset the capital costs incurred with use of such gases as supplemental boiler fuel, even when SO_2 removal costs are included. For low-pressure lock gas there is a small energy penalty, and incremental capital costs are large relative to the pollutant loading. For transient gases, a relatively large annualized cost occurs with boiler incineration, since only a small annual energy recovery is realized for this intermittent stream and since oversizing of transport and boiler systems must be based on maximum flow rates.

The Stretford absorber vent gases contain sufficient energy value that capital costs associated with boiler incineration are nearly offset by recovered energy. When SO_2 removal is added, a relatively large capital increment is incurred, so that overall costs for incineration plus SO_2 removal are high relative to the amount of sulfur removal. When the Stretford oxidizer vent gas is substituted for air in the boiler system, both a capital cost and an energy penalty result since the inert portion of the vent gas (which is larger than that of air) must be carried through the boiler system.

4.2 AQUEOUS MEDIUM

This section discusses the control of wastewaters produced by Lurgi-based synfuels plants. Information presented includes:

- a summary of the waste stream characteristics and flow rates (from Section 3),
- a general discussion of the wastewater treatment processes which are potentially applicable,
- illustrative examples of the application of individual control processes to specific streams, and
- examples of the sequential application of several control processes for the treatment and ultimate disposal of specific streams or combinations of streams.

The main emphasis in Section 4.2 is on control measures for wastewater streams which are unique to Lurgi-based synfuels plants. Since the treatment and reuse/disposal of gas liquor is the primary wastewater treatment challenge for Lurgi-based synfuels plants, this section concentrates on that stream. Treatment techniques for wastewater streams which are not unique to Lurgi-based synfuels plants (such as coal pile runoff) are not discussed in depth in this manual. Standard treatment methods for these non-unique streams have been developed in existing U.S. industries, and these methods should generally be applicable to the non-unique streams generated in Lurgi-based synfuels plants.

A key concept in this discussion of the control of wastewaters from Lurgi-based synfuels plants is the classification of these wastewaters into two source types:

- streams containing primarily organic compounds and
- streams containing primarily inorganic compounds.

The use of these source types and the organization of the individual stream control technology presentations by source types allow the grouping of streams with similar characteristics and potentially applicable controls. Secondary wastewater streams produced by pollution controls for gaseous or solid waste streams are also discussed in this section within their applicable source types. Controls for aqueous waste streams produced by water pollution controls are discussed along with the discussions of the control processes that generate them. Controls for secondary gaseous and solid wastes are discussed in their media sections (Sections 4.1 and 4.3), respectively.

Much of the characterization data for wastewaters which are unique to Lurgi-based synfuels plants is based on data from full-scale synfuels plants. Some of the potential Lurgi wastewater streams, however, have not been tested, and therefore, the characterizations given here and in Section 3 for those streams are estimates based on the available information. In contrast, most of the wastewater treatment processes discussed in this section have not been used to treat Lurgi wastewaters. Therefore, many of the performance and cost estimates given in this manual are based on extrapolations of existing data from related industries. Section 5 summarizes the gaps and limitations of the data base used to develop this manual.

Table 4-36 gives a summary of the wastewater streams which could be generated by Lurgi-based synfuels plants. This table also gives estimated flow rates for the plant configurations and sizes discussed in Section 3. Pollutants of potential concern and factors affecting stream characteristics are also given.

The rest of this section presents general information on the water pollution control processes which could potentially be applied to the two wastewater source types described above (Section 4.2.1), and examples of

TABLE 4-36. SUMMARY OF UNCONTROLLED AQUEOUS WASTE STREAMS GENERATED IN LURGI-BASED SYNFUELS FACILITIES

Stream (Stream No.)	Pollutants of Potential Concern	Factors Affecting Effluent Stream Characteristics	Synthesis Process	Wastewater Stream Flows (m³/hr)		
				Coal Feedstock		
				Rosebud	Illinois No. 6	Dunn Lignite
Waste Streams From Main Process Train						
Gas Liquor (210)	Suspended solids (coal dust), dissolved inorganics, (NH_3, acid gases, trace metals), suspended tars/oils, and dissolved organics (phenols, organic acids, other water-soluble organics)	Feed coal properties, gasifier and gas cooling section operating conditions	Indirect Liquefaction SNG	293 281	495 476	433 418
Rectisol condensate/still bottoms from acid gas removal (AGR) system (216)	Dissolved organics and inorganics including acid gases, blowdown solvent and solvent degradation products	The AGR process used and its operating characteristics, properties of the inlet raw gas (e.g., flow, temperature, moisture content)	All	10	12	10
Methanation (228) and CO_2 removal condensates (238)	Negligible quantities of dissolved gases (e.g., CO_2)	Synthesis process purge gas characteristics	SNG Methanol F-T Mobil	54 21 19 21	56 8 20 8	54 15 19 15
Synthesis process wastewaters: Methanol (237); Fischer-Tropsch (219); Mobil (225)	Dissolved organics (alcohols, organics acids, other hydrocarbons)	Synthesis section operating conditions and feed gas properties	Methanol F-T Mobil M	5 76 55	1 72 58	4 72 56
Gasifier ash quench blowdown (404)	Suspended solids, pH, inorganics leached from the ash and inlet ash quench water components	Source of quench water and ash characteristics	All	No net discharge - this stream is assumed to be contained and recycled. Blowdown is in the form of water associated with the wet ash.		
Raw coal storage runoff (201)	Suspended solids (coal fines) and inorganics leached from the coal	Coal type and conditions of wastewater contact with coal (e.g., residence time and temperature). Rainfall rates, coal storage, and washing practices.	All	0.7	1.8	1.1

(Continued)

TABLE 4-36. (Continued)

Stream (Stream No.)	Pollutants of Potential Concern	Factors Affecting Effluent Stream Characteristics	Synthesis Process	Wastewater Stream Flows (m^3/hr) Coal Feedstock Rosebud	Illinois No. 6	Dunn Lignite
Waste Streams from Auxiliary Processes						
Demineralizer regeneration wastewaters (301)	Dissolved inorganics (e.g., Na^+, $SO_4^=$), and raw water contaminants	Makeup water flow and composition	All	45	68	50
Boiler blowdown (303)	Dissolved inorganics (silica, metals)	Makeup water quality and boiler operating pressure	All	4	5	4
Cooling tower blowdown (307)	Dissolved inorganics and possibly organics, including makeup water components and treatment chemical residuals	Makeup water quality and cooling tower operating characteristics	Methanol F-T Mobil M SNG	66 92 79 66	66 92 79 66	66 92 79 66
Boiler (305) and process equipment (320) cleaning wastes	Organics, inorganics, cleaning chemicals, and metals removed from equipment surfaces	Waste stream source; plant operating, maintenance, and equipment cleaning practices	All	Flow rates expected to be highly variable, but small compared to the above.		
Boiler bottom ash quench/sluice system blowdown (407)	Suspended solids, pH, inorganics leached from the ash and inlet ash quench water components	Source of quench water and ash characteristics	All	No net discharge - this stream is assumed to be contained and recycled. Blowdown is the water associated with the wet ash.		
Waste Streams from Pollution Control Processes						
Stretford solution blowdown (416)	Vanadium salts, thiocyanates, and thiosulfates	Coal sulfur content, gasifier operating conditions, and Stretford unit design and operation	All	2.2	4.3	2.2
Beavon (240) and SCOT (241) condensates	H_2S, and NH_3	Unit design and operating conditions.	All	4	4	4
Wellman-Lord sulfate purge (242)	Sulfites, sulfates, and polysulfites	Coal sulfur content and Wellman-Lord unit design	All	5	5	5

(Continued)

TABLE 4-36. (Continued)

Stream (Stream No.)	Pollutants of Potential Concern	Factors Affecting Effluent Stream Characteristics	Synthesis Process	Wastewater Stream Flows (m^3/hr) Coal Feedstock		
				Rosebud	Illinois No. 6	Dunn Lignite
Blowdown streams from vent gas scrubbers.	Depends on source; coal fines, tars, oils, dissolved organics, and inorganics including acid gases	Vent gas and scrubber makeup water quality	All	Flowrates are unknown, but expected to be small		
Waste Streams from Auxiliary Processes						
Plant process drain (318) effluent	Any of the above	Plant operating and maintenance practices	All		20 to 25	
Storm drain (319) effluent	Any of the above	Rainfall rates, collection system design, and plant housekeeping practices	All	14	47	18

applications of control processes to specific streams (Sections 4.2.2 and 4.2.3). General information about the potential wastewater controls is given in a single section (4.2.1), rather than in separate sections for each source type. This approach has been taken to avoid repetition since many water treatment processes are applicable to streams of both source types.

4.2.1 Aqueous Medium Generic Controls

The water pollution control processes discussed in this manual include techniques for:

- removal of suspended solids, tars, and oils (Section 4.2.1.1);
- removal of bulk organics (4.2.1.2);
- removal of dissolved gases (4.2.1.3);
- removal of dissolved organics (4.2.1.4);
- removal of residual organics (4.2.1.5);
- removal of dissolved inorganics (4.2.1.6);
- volume reduction (4.2.1.7); and
- residual disposal (4.2.1.8).

The information given here is derived from data on industrial applications and laboratory tests with various wastewaters. Available information is given describing each process, its performance and factors affecting performance, secondary wastes produced, reliability, and estimated costs on a unit throughput basis. The water pollution control technologies discussed here represent a wide, but not all-inclusive, range of the processes which could be used in the treatment of wastewaters from Lurgi-based synfuels plants. The information given in this section is specific to wastewater streams from Lurgi-based synfuels plants. Sections 4.2.2 and 4.2.3 discuss examples of the application of specific wastewater treatment processes to specific wastewater streams from Lurgi-based synfuels plants.

A more detailed discussion of each control process may be found in the PCTM Pollution Control Technology Appendices.

4.2.1.1 Processes for Removal of Suspended Solids, Tars, and Oils

The removal of settleable solids and floating material from wastewaters is desirable for a number of reasons. First, if downstream treatment equipment is present, the removal of these contaminants helps avoid problems due to plugging or fouling of that equipment. Second, the tars and oils may be recovered for their fuel or byproduct value. Third, it reduces the load on downstream processing units and thus lowers their capital and total annualized costs.

Suspended solids and free oils and tars may be removed from wastewater by a number of different processes. The selection of a given process or series of processes depends on a number of factors such as particle size, particle density relative to the wastewater, settleability of the particles, miscibility of the contaminants with the wastewater, and tendency of the particles to form colloidal suspensions.

Processes potentially applicable for the removal of suspended solids, tars, and oils from Lurgi gasification wastewaters include screening, gravity separation, coagulation/flocculation, air flotation, and filtration. Table 4-37 gives some summary information about these processes. Screening is generally used for removing relatively large particles. The amount of solids removed depends on screen size and wastewater characteristics such as the size distribution of suspended solids in the wastewater. Screening is often included as a pretreatment step before other suspended solids, tars, and oil removal procedures. The rest of this section (Section 4.2.1.1) summarizes available information for the remaining processes listed above.

TABLE 4-37. TECHNOLOGIES POTENTIALLY APPLICABLE TO THE REMOVAL OF SUSPENDED SOLIDS, TARS, AND OILS FROM LURGI-BASED SYNFUELS PLANT WASTEWATERS

Technology	Technology Principle	Components Removed	Removal Efficiency	Feed Requirements/ Restrictions	Byproducts and Waste	Comments
Gravity Separation	Provision of adequate residence time in a stagnant vessel to allow suspended solids or immiscible fluids to separate into lighter- and heavier-than-water phases.	Nonemulsified free oils, tars, and settleable particulates.	Depends on design; 10-50% removal of TSS typical, 60-99% for free oils.	Minimum feed stream turbulence.	Recovered light oils (s.g. <1), heavy tars, and solid sediments (s.g. >1).	Incorporated into the tar/oil separation system of all existing Lurgi gasification plants.
Coagulation/ Flocculation	Use of agents to promote coalescence of fine suspended solids and adsorption of tars and oils; generally used in conjunction with other processes (e.g. gravity separation, filtration).	Fine suspended solids, colloids, and some heavy metals.	Outlet suspended solids concentration to 10 mg/L possible, oils removal 60-95%.	A wide range of commercial flocculants are available for treating range of wastewaters.	Same as gravity separation.	Widely used in water treatment systems to remove fine solids and colloids. Often used in conjunction with other processes (e.g. chemical precipitation, filtration, air flotation).
Air Flotation	Use of air bubbles to promote the disengagement of lighter-than-water particles.	Fine suspended solids, oils, and grease. Useful for removing suspended materials with densities close to that of water.	Depends on characteristics of source and treatment process; TSS removal of 2-75%, oil removals of 75-85% typical. Higher when combined with flocculation.	Air requirements depend upon waste characteristics.	Recovered oils, entrained solids, and sludge.	Subject to variations in influent wastewater flow and loading if not combined with chemical pretreatment.
Filtration	Passing wastewater through suitable filter medium; filter material cleaned by backwashing or discarded.	Suspended solids, oil; size of particles removed depends on coarseness of media, pretreatment, etc.	TSS removal 30-70%; with flocculation/ coagulation between 80-98%; oil removals 66-90% for refinery API separator effluent.	Generally applicable for wastewaters with 5-250 mg/L of TSS, up to 200 mg/L oil.	Filter backwash, and spent filter media.	Utilized to treat wastewater in commercial Lurgi gasification plants. "Sticky" tars/oil may cause filter plugging and regeneration problems.
Screening	Passing wastewater through a wire mesh, parallel bars, or similar device.	Suspended particles; size removal depends on screen mesh size; often removes only larger particulates.	Depends on size distribution of particulates in waste and screen size used.	Tars and oils can foul screen.	Recovered particles.	Often used as a pretreatment step for the removal of large debris.

Gravity Separation

The removal of suspended tars and oils by gravity separation is currently utilized in all operating Lurgi gasification facilities. This process is often considered an integral part of the byproduct recovery operation.

Gravity separation relies upon the differences in density between immiscible oil, water, and suspended solids for successful operation. Byproduct oils in Lurgi wastewater, which are lighter than water, can be removed from the top of the aqueous phase, while heavy tars and solid particles sink to the bottom of the separator vessel.

The design of oil-water separators used in refinery wastewater applications has been well-defined in studies by the American Petroleum Institute (API). In API separators, the influent wastewater passes through trash bars and a skimmer to remove floating oil before entering the quiescent zone of the separator. In this quiescent zone, the wastewater velocity is kept very low to avoid turbulent mixing. An adjustable weir at the end of the separator divides the waste into aqueous and organic phases. A rotating skimmer is used to remove the organic phase from the surface. The bottom of the separator contains slowly moving panels which convey the settled solids to a pump.

Typical removal efficiencies for oil/water separators range from 60 to 99 percent for free oils and 10 to 50 percent for suspended solids. Removal efficiencies depend on a number of factors including relative densities of oil, water, and solids; particle size; separator configurations; and retention time.

Secondary waste streams produced by the gravity separation of Lurgi wastewaters are the light oil skimmed from the surface of the wastewater and heavy tars, oils, and solid sediments removed from the bottom of the separator. In addition, if the wastewater being treated contains significant quantities of dissolved gases, it may be desirable to collect these gases and combine them with other gas streams for treatment.

Gravity separation has been widely used in many different industries for many years. The process is a highly reliable method of separating non-emulsified oil from wastewater providing the equipment is properly controlled and regularly maintained and wastewater flow rates and compositions do not vary widely.

For API separator applications in Lurgi-based synfuels plants, capital investment requirements for treating 100 m^3/hr of wastewater are estimated to be \$800 per m^3/hr.

Coagulation/Flocculation

Coagulation and flocculation are techniques for enhancing the gravity separation of suspended tars, oils, and solids from a wastewater through the addition of chemicals. Coagulation is the process of destabilizing colloidal particles by neutralizing surface charges built up on the particle surfaces. Common chemicals used for coagulation include alum, lime, and ferric sulfate. Flocculation is the formation of settleable particles from destabilized colloidal-sized particles by coalescence and physical enmeshment. Common flocculation aids are polymers, activated silica, and polyelectrolytes.

The equipment generally required for coagulation/flocculation consists of a mixing tank (where the appropriate coagulants, polymers, and pH adjustment chemicals are added to the wastewater) and a sedimentation basin or clarifier (which provides retention time for the settling of the coagulated solids). Facilities must also be provided for storing, diluting (or dissolving), and metering the chemicals.

Reported removal efficiencies for oils range from 61 to 95 percent, while suspended solids concentrations as low as 10 mg/L can be achieved in a properly designed system. Performance depends strongly on the composition and concentration of impurities in the wastewater being treated. The use and dosages of specific coagulants/flocculants are generally determined by the use of jar tests and field trials.

The major waste stream produced by coagulation/ flocculation is the sludge stream. It typically contains 1 to 2 percent solids, is quite gelatinous, and may be difficult to dewater. The sludge will contain insoluble metal hydroxides and entrapped solids. Adjustment of the sludge pH may be required prior to subsequent treatment or disposal.

Coagulation and flocculation have shown good reliability both from a performance and mechanical standpoint. They have been proven over a number of years of successful operation. The key to reliable performance lies in keeping the influent wastewater composition and flow rate as constant as possible. Mechanical reliability depends on the use of proper materials of construction since some coagulation/flocculation chemicals are extremely corrosive.

A coagulation/flocculation system consisting of alum and polymer storage, feed, and mixing equipment is estimated to require a capital investment (for treating 100 m^3/hr of wastewater in Lurgi-based synfuels plants) of approximately $1000 per m^3/hr of wastewater flow.

Air Flotation

Air flotation removes small particles, oil, and grease from aqueous streams by passing small gas bubbles through the wastewater. The bubbles adhere to the small particles, reducing their apparent density. The resulting froth rises to the surface where it is skimmed off. The process is often used in conjunction with coagulation/flocculation to improve removal efficiencies for colloidal suspensions or emulsified oils. Air flotation is especially attractive for the removal of particles with densities close to that of water.

Two types of flotation units are currently used: dissolved air flotation (DAF) and induced air flotation (IAF). DAF involves saturating water with air under pressure (typically between 0.27 to 0.58 MPa). The gas-saturated water is then depressurized in a flotation vessel, causing the formation of small bubbles. Retention times of 20 to 60 minutes are typical for DAF units.

IAF units operate by mechanically dispersing the gas into the wastewater by the use of a rotor-disperser. A typical IAF unit consists of four flotation cells each of which has a retention time of about one minute.

Air flotation is capable of removing a wide range of suspended solids, oils, and greases from wastewater streams. Total oil removals of 75 to 85 percent are typically achieved while solids removals of 20 to 75 percent are expected. When combined with flocculation, free oil removals of 97 percent or more and suspended solids removals of 80 to 93 percent can be achieved.

Air flotation produces two major secondary waste streams. The first is the froth skimmed from the surface of the wastewaters which contains oils and entrapped solid particles. The second is the sludge consisting of solids having densities greater than that of water.

Air flotation has been demonstrated over many years to be a reliable process. The mechanical reliability is high since the equipment required is simple. Performance reliability depends on minimizing variations in the influent wastewater flow rate, suspended solids, oil, and grease loadings, temperature, and pH. Chemical pretreatment helps reduce the adverse effects of such changes on reliability.

For dissolved air flotation applications in Lurgi-based synfuels plants, capital investment requirements for treating 100 m^3/hr of wastewater are estimated to be $4700 per m^3 of wastewater flow.

Filtration

Granular-media filtration is one of the oldest and most widely used methods for the removal of suspended solids, oils, and tars from wastewater streams. Although other types of filtration processes are available, this manual discusses only granular-media filtration for Lurgi wastewaters applications. Granular-media filtration is currently used to treat wastewaters in a number of Lurgi-based coal gasification facilities. The wastewater flows either by gravity or under pressure through a bed of inert material which physically retains the solids. Materials used as filter media include sand, anthracite, resins, and garnet; combinations of these materials are used in multimedia filters. The filter bed is contained in a basin or tank and is supported by an underdrain system that retains the filter medium while the filtered liquid is drawn off. Other equipment used in typical filtration systems includes facilities for backwash storage and pumping (for cleaning the filter bed after it becomes loaded with retained solids), plus piping and valving to permit backwashing of some units while others are on line.

Suspended solids removals for granular media filtration range from 30 to 70 percent without pretreatment and between 80 to 98 percent when preceded with flocculation and/or coagulation. Performance data have not been reported for filters in Lurgi gasification plants.

Granular-media filtration produces one secondary waste stream intermittently (backwash effluent) and, periodically, spent filter media. The volume of the backwash stream is generally between 2 to 10 percent of the filtered wastewater volume, and hence contains 10 to 50 percent higher concentrations of suspended solids and oil than the original wastewater.

Granular-media filtration is very reliable both from a performance and mechanical standpoint. Pilot tests generally performed prior to designing full-scale treatment processes serve to increase performance reliability. Mechanical reliability is primarily dependent on adequate cleaning of the filter bed, air and/or water scouring, surface washing, and special media cleaning solvents are commonly used to enhance cleaning of the filter bed and thus reduce operating problems.

For granular-media filtration applications in Lurgi-based synfuels plants, capital investment requirements are estimated to range from $1800 to $2500 per m^3/hr of wastewater treated, for wastewater flows of 300 and 100 m^3/hr, respectively.

4.2.1.2 Processes for Removal of Bulk Organics

For wastewaters with high organic contents, it is often desirable to perform an initial bulk organics removal step prior to treatment in processes which are designed to produce effluents with relatively low concentrations of organic compounds. Bulk organics removal may be desirable for several reasons. First, it may be economically attractive to recover the organics for fuel or byproducts. Second, bulk organics removal may be a necessary pretreatment step before the application of processes which will produce a desired effluent or recycle water quality. And, third, the lower capital and total annualized costs for downstream processing units (attainable if a bulk organics removal step is employed) may more than offset the cost of the bulk organics removal process.

Table 4-38 presents a brief summary of information on two bulk organics removal processes: solvent extraction and wet air oxidation. The rest of this section (4.2.1.2) summarizes available information for these two processes. These are not the only processes which could be used for bulk organics removal. They were selected as examples of processes which could be used to remove bulk organics from Lurgi-based synfuels plant wastewaters. It should be noted that these two processes could also be used in some applications for residual organics removal.

Solvent Extraction

Solvent extraction processes are often used to remove dissolved organics such as phenols from process wastewaters. These processes consist primarily of two steps. First, an extraction step in which the solvent extracts the dissolved organics from the wastewater, and second, a regeneration step in

TABLE 4-38. TECHNOLOGIES POTENTIALLY APPLICABLE TO THE REMOVAL OF BULK ORGANICS FROM LURGI-BASED SYNFUELS PLANT WASTEWATERS

Technology	Technology Principle	Components Removed	Removal Efficiency	Feed Requirements/ Restrictions	Byproducts and Waste	Comments
Solvent Extraction	Extraction of organics from wastewater via contact with an immiscible solvent. By-product organic liquids recovered from the solvent in a separate regeneration step.	Phenols, TOC, BOD, COD, and other organics.	For the Phenosolvan process, 99.5% removal of monohydric phenols, 60% for dihydric phenols, and 15% for other organics typical.	Sensitive to suspended matter in wastewater, makeup solvent is the only major raw material.	Crude phenols, filter backwash, and spent filter media.	This is the basis for the Phenosolvan process used in all major Lurgi facilities.
Wet Air Oxidation	Direct reaction of O_2 with wastewater in a closed, pressurized vessel at elevated temperatures.	TOC, BOD, COD, and some inorganic pollutants. Destruction of difficult to treat organics can be achieved.	80-90% removal of COD is possible in a system with a residence time of one hour or greater; 99+% phenolics destruction.	Air or oxygen; heat if autothermic reaction conditions are not present.	Vent gases containing CO, CO_2, light hydrocarbons, NH_3, and sulfur species.	Promising but not proven in this application; fairly rigorous materials of construction requirements.

which the removed organics are separated from the solvent. Countercurrent extraction columns and distillation columns are used in these processes. Use of solvent extraction is generally applicable to wastewaters containing at least 2000 mg/l of extractable organics and having a flow rate of at least 11 m^3/hr.

A wide variety of solvents can be used in extraction processes including benzene, tricresyl phosphate, isopropyl ether, aliphatic esters (such as n-butyl acetate), light oils, light aromatics, sodium hydroxide solutions, and various proprietary solvents. The most commonly used process for removing bulk dissolved organics from Lurgi gas liquors is the Phenosolvan process. This process is also included in virtually all proposed Lurgi plant designs and is part of Lurgi's proprietary design package. Although this process is discussed as one of the water pollution control processes in this manual, in most Lurgi-based synfuels projects the Phenosolvan process is, for all practical purposes, part of the Lurgi base plant. The Phenosolvan process is a proprietary solvent extraction process developed by Lurgi to extract phenols and other water soluble organic compounds from process wastewaters. A simplified flow diagram for this process is shown in Figure 4-6. In this process, the gas liquor is filtered and fed to a series of mixer-settlers where it contacts a lean organic solvent (such as butyl acetate or diisopropyl ether) in countercurrent flow contactors. After solvent-water phase separation (not shown in the diagram), the rich solvent is sent to a distillation column for solvent recovery. The lean solvent from the column returns to the mixer-settlers while crude phenol is stripped for residual solvent recovery.

The extracted wastewater from the mixer-settlers is stripped with nitrogen to recover residual solvent. The solvent-rich nitrogen gas is then contacted with a crude phenol slipstream from the crude phenol stripper to

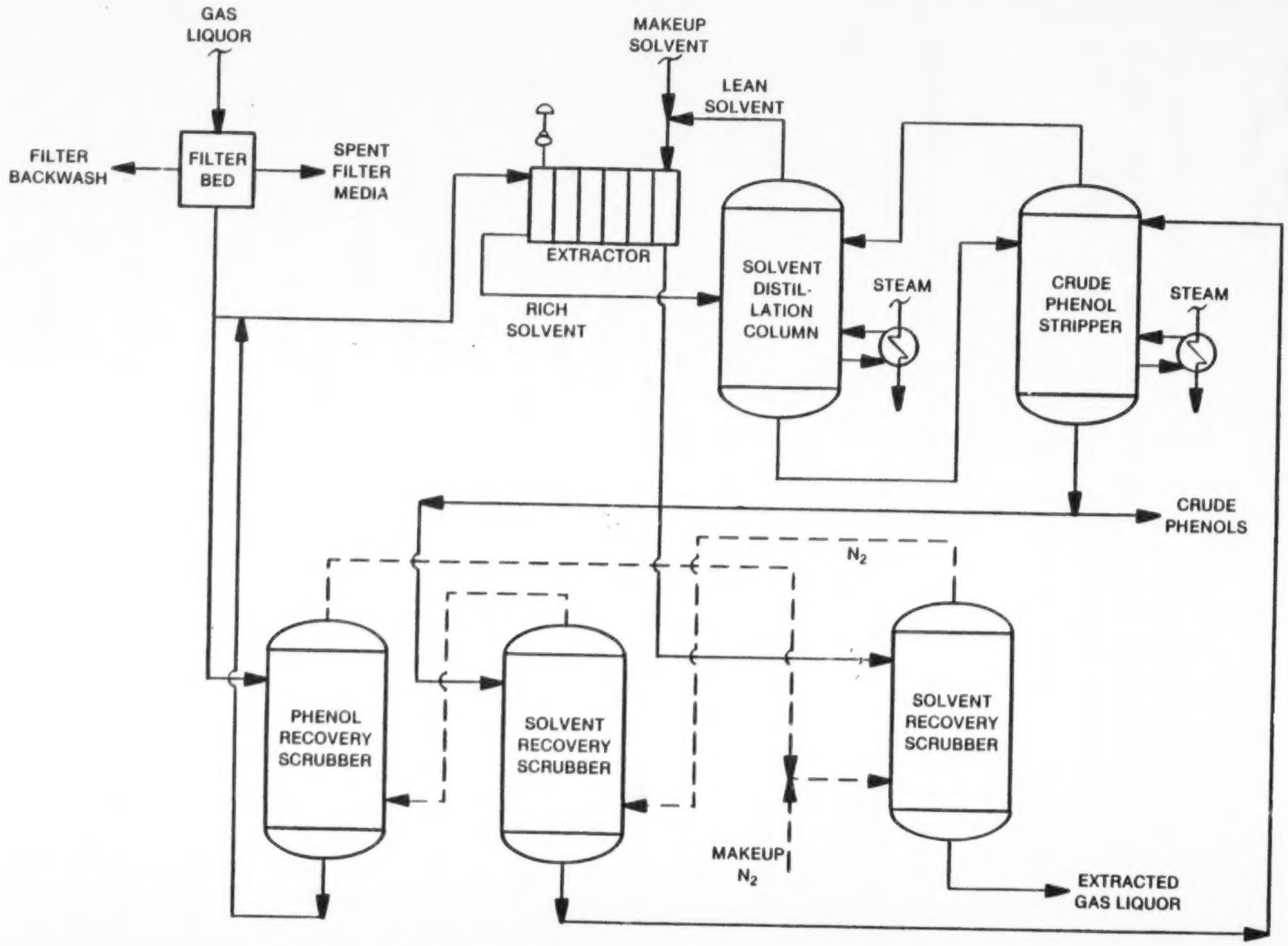

Figure 4-6. Phenosolvan solvent extraction process

recover most of the solvent. Phenolic vapors remaining in the nitrogen gas are then removed via contact with a portion of the feed wastewater. The clean gas returns to the solvent recovery scrubber and the feed wastewater proceeds to the mixer-settlers.

Extraction efficiencies for the Phenosolvan process are estimated at:

- 99.5% for monohydric phenols,
- 60% for polyhydric phenols, and
- 15% for organic acids.

Low volume air emissions from various unit operations (e.g., solvent storage tank vents), spent filter media, and filter backwash are secondary waste streams from the Phenosolvan process. The crude phenol stream recovered by the Phenosolvan process is more appropriately considered a by-product than a waste stream.

The Phenosolvan process has been commercially available for over 40 years. Although there are no publicly available data on the operating histories of the over 30 commercial installations, the continued use of this process tends to indicate it has adequate reliability.

For Phenosolvan applications in Lurgi-based synfuels plants, a representative capital investment requirement is $35,000 per m^3/hr for a wastewater flow of 300 m^3/hr.

Wet Air Oxidation

Although the wet air oxidation process could be used to remove bulk organics from Lurgi wastewaters, it has not been proven in that application.

The good commercial record of the Phenosolvan process in this application and the fact that the Phenosolvan process is part of Lurgi's proprietary gasification package have tended to discourage development of alternate approaches for application to Lurgi-based systems. The primary advantage of the wet air oxidation process in this service is that the process might not require any auxiliary fuel and might even be adapted to recover byproduct energy in the form of steam. Economics tend to limit wet air oxidation to small volume streams having relatively high organics concentrations. (Another potential application of wet air oxidation to a Lurgi-based synfuels plant is in the regeneration of spent activated carbon in systems which use activated carbon enhancement of activated sludge.)

In the wet air oxidation process, dissolved or suspended organics are oxidized by direct contact with compressed air or oxygen at elevated temperatures and pressures. Temperatures of about 590 K, pressures up to 21 MPa, and residence times of one hour or more are often used to destroy certain toxic compounds, but less severe conditions can achieve significant reductions in organic loadings.

Wet air oxidation is capable of reducing the concentration of both organic and inorganic COD in wastewater streams. The reduction achieved for a given waste depends on the operating temperature and pressure, presence of catalyst, and the nature of the waste itself. COD removals of greater than 80 to 90 percent have been reported while greater than 99 percent destruction of phenolic compounds has been achieved. Whether these levels of destruction can be achieved with Lurgi wastewaters is not known. Bench- or pilot-scale studies would need to be performed on actual wastewaters.

The secondary waste stream produced by wet air oxidation consists of the offgas produced as a result of waste oxidation. Depending on the nature of the influent, the offgas may contain ammonia, volatile organics, carbon monoxide, and carbon dioxide. The flow rate of this stream depends on the flow rate of air (or oxygen) required to oxidize the waste.

Information on the reliability of the wet air oxidation process is limited, but careful operator attention is reportedly required.

For wet air oxidation of high strength wastewaters like those found in Lurgi-based synfuels plants, a representative capital investment requirement is $490,000 per m^3/hr of wastewater flow for treating 300 m^3/hr of wastewater.

4.2.1.3 Processes for Removal of Dissolved Gases

A number of aqueous wastes produced in a Lurgi-based synfuels facility may contain dissolved gases such as ammonia, carbon dioxide, hydrogen sulfide, hydrogen cyanide, and/or volatile organics. Removal of dissolved gases may be desirable to reduce gaseous emissions from downstream water treatment units, to reduce dissolved gas loadings in downstream treatment units, and to recover potentially saleable byproducts.

Removal of these gases is normally accomplished by stripping. Five technologies which appear to be applicable to Lurgi-based synfuels plants are discussed:

- Steam Stripping,
- PHOSAM-W,
- Chevron WWT,
- Inert Gas Stripping, and
- Vacuum distillation.

Table 4-39 gives a brief summary of information presented in the text.

Steam Stripping

Steam stripping is used to remove ammonia, hydrogen sulfide, carbon dioxide, phenols, cyanides, organics, and other volatile compounds from wastewater. The stripped gases and vapors can be further processed, recovered, or destroyed. The stripped wastewater passes to further treatment or re-use. If large amounts of ammonia are in the wastewater, the basic steam stripping process may be expanded to include the recovery of ammonia. (See the description of PHOSAM-W and Chevron WWT which follows this steam stripping discussion.)

TABLE 6-39 TECHNOLOGIES POTENTIALLY APPLICABLE TO THE REMOVAL OF
DISSOLVED GASES FROM COAL-BASED SYNFUELS PLANT WASTEWATERS

Technology	Technology Principle	Components Removed	Removal Efficiency	Feed Requirements/ Restrictions	Byproducts and Wastes	Comments
Steam Stripping	Increasing temperature and providing a positive flow of an inert material (steam) through the wastewater; removes volatile organics and inorganics with overhead stream.	NH_3, acid gases (CO_2, H_2S, HCN), and light hydrocarbons (phenols).	95-99% removal of "free" ammonia and acid gases typical; hydrocarbon removal varies with volatility of stripped components.	Feed preheat can be used to reduce steam requirements; acid/caustic for pH adjustment optional.	Stripped acid gases and volatile compounds are in gaseous secondary waste-stream.	Acid/caustic addition can be used to improve the efficiency and selectivity of the stripping process.
PHOSAM-W	Initially same as steam stripping, but ammonia is scrubbed from the stripper overhead stream by absorption in a phosphoric acid solution. Ammonia is then separated from phosphoric acid and water which are both reused in the process.	Same as steam stripping.	Same as steam stripping.	Same as steam stripping.	Anhydrous ammonia by-product. Stripped acid gases and volatile compounds are in gaseous secondary waste stream.	Process is a derivative of the PHOSAM process which removes ammonia from coke oven gases.
Chevron WWT	Similar to steam stripping except that ammonia is not removed in the initial stripper. A second stripper removes ammonia, which is subsequently purified to produce anhydrous ammonia byproduct.	Same as steam stripping.	Same as steam stripping.	Same as steam stripping.	Same as PHOSAM-W.	Process was designed for refinery sour waters, but is said to be capable of treating synfuels plant wastewater.
Inert Gas Stripping	Air (or other inert gas) is passed through wastewater promoting the desorption of dissolved gases.	Same as steam stripping.	Depends on specific design factors (such as the pressure and flow rate of the inert gas) and on the wastewater characteristics. Removals similar to steam stripping are achievable.	Best applied on on low flow rate wastewater streams with low levels of ammonia and CO_2.	Stripped acid gases and volatile compounds which are diluted by the inert gas stream.	Dilution of the offgas stream makes treatment difficult. Therefore, this process is probably limited to wastewaters whose dissolved gases can be vented.
Vacuum Distillation	Total system pressure is lowered. Vapor pressure of the dissolved gases then drives portions of them into the vapor phase.	Same as steam stripping.	Removals similar to steam stripping are achievable, but the energy cost for this performance is high.	Some precooling of the inlet wastewater may be required to prevent excessive vaporization of water.	Same as steam stripping except acid gas waste stream is at lower temperature and therefore has lower water vapor content.	High energy costs for the desired removals in synfuels plant applications make this process less likely to be used.

Steam stripping is usually conducted as a continuous operation in a packed tower or conventional fractionating column (bubble cap or sieve tray) with more than one stage of vapor/liquid contact. The wastewater feed is first preheated by heat exchange with stripped wastewater. The preheated water enters near the top of the stripping column and then flows by gravity countercurrent to steam and vapor rising from the bottom of the stripper. As the wastewater flows downward, it is heated and volatile compounds and gases are stripped by the steam and vapors rising from the bottom of the stripper.

The performance of steam stripping depends on the characteristics of the wastewater feed and the stripper design. The most efficient strippers are generally able to remove ammonia down to 50 to 100 mg/L, but some can achieve levels of 15 mg/L or less. The degree of ammonia removal obtainable will be influenced by the ratio of free-to-fixed ammonia present in the wastewater. Strippers achieving ammonia levels of less than 100 mg/L remove hydrogen sulfide to 0 to 30 mg/L depending on the initial ammonia, hydrogen sulfide, and carbon dioxide concentrations. Carbon dioxide is totally stripped. For several types of wastewaters from synfuels facilities, typically 17 to 22 percent of the residual phenols are stripped. For refinery type wastewaters, unrefluxed strippers on the average remove 33 percent of the phenols, and refluxed strippers on the average remove 39 percent of the phenols. Cyanide removal efficiencies are reported to vary widely but average 37 percent for stripping refinery-type wastewaters.

The only secondary waste stream from steam stripping is the stripped gas or vapor which exits the stripper. This stream is saturated with water and contains all of the stripped gases and vapors. It may be processed to recover specific components or treated to destroy (or otherwise control) specific pollutants.

In refinery applications steam stripping has proven to be highly dependable.

For steam stripping applications in Lurgi-based synfuels plants, a representative capital investment requirement is \$4,000 per m^3/hr of wastewater flow for treating 300 m^3/hr of wastewater. This cost estimate does not include the costs associated with treating the stripped gas stream.

PHOSAM-W

PHOSAM-W (Figure 4-7) is a proprietary process for removing and recovering dissolved gases from wastewaters. It was originally developed by USS Engineers and Consultants Incorporated. This process is a revision of the original PHOSAM process to recover ammonia from coke oven gases.

In the PHOSAM-W process, the wastewater stream is first steam stripped to vaporize and remove ammonia and other dissolved gases and volatile compounds. The stripped vapors are then scrubbed with a phosphoric acid solution to recover ammonia. The remaining acid gases and volatile compounds exit as the absorber overhead gases, which are a secondary waste stream. The absorbed ammonia is first removed from the phosphoric acid solution in a stripper and then distilled to remove water, producing a liquid byproduct ammonia stream.

Most strippers are designed to remove free ammonia down to 50 to 100 mg/L, but some can achieve levels of 15 mg/L or less depending on the levels of fixed ammonia in the wastewater. Strippers achieving ammonia levels of less than 100 mg/L will generally remove hydrogen sulfide to 0 to 30 mg/L depending on the initial ammonia, hydrogen sulfide, and carbon dioxide concentrations. Carbon dioxide is totally stripped. For several types of wastewaters from synfuels facilities, typically 17 to 22 percent of the residual

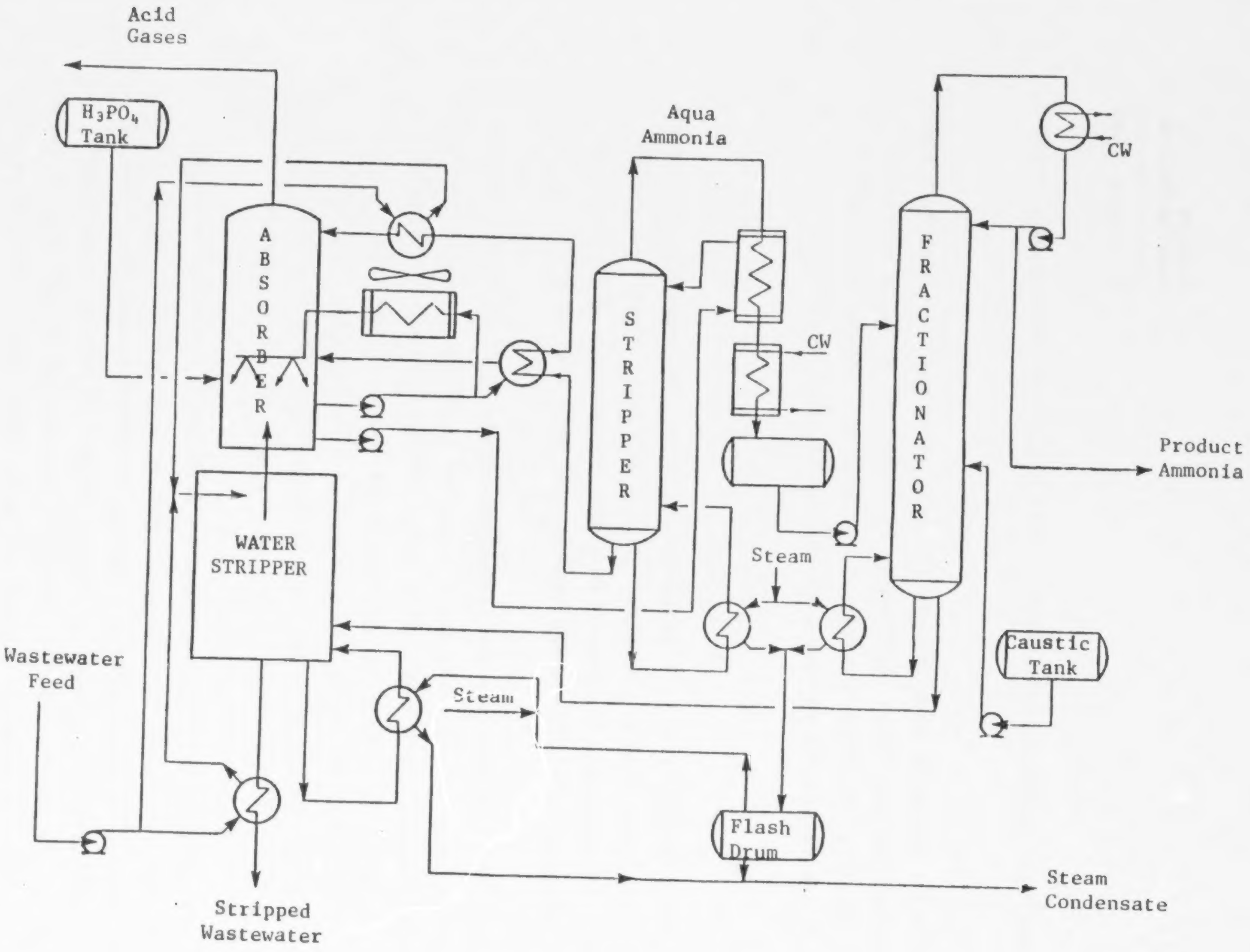

Figure 4-7. The PHOSAM-W process

phenols are stripped. For refinery-type wastewaters, unrefluxed strippers on the average remove 55 percent of the phenols and refluxed strippers on the average remove 39 percent of the phenols. Cyanide removal efficiencies are reported to vary widely but average 37 percent for stripping refinery-type wastewaters.

For this manual, the PHOSAM-W process is estimated to achieve the following residual wastewater concentrations:

Component	mg/L
Ammonia	150
H_2S	1
CO_2	1

In addition, a 50% removal of HCN has been assumed.

The only secondary waste stream from a PHOSAM-W plant is the acid gas or vapor which exits the ammonia absorber. This stream is saturated with water and contains acid gases such as carbon dioxide and hydrogen sulfide and other volatile compounds. This stream also contains a small amount of ammonia, typically comprising 0.1 to 0.5 percent of the total gas volume.

The original PHOSAM process has been operated reliably in several plants for up to 10 years, with a service factor of about 95 percent. No data are available on commercial application of the PHOSAM-W process, but this process has been proposed for use in several new U.S. synfuels plants.

For PHOSAM-W applications in Lurgi-based synfuels plants, a representative capital investment requirement is $35,000 per m³/hr of wastewater flow for treating 300 m³/hr of wastewater. This cost estimate includes equipment for recovering ammonia as a byproduct, but does not include the costs associated with treating the stripped acid gases.

Chevron WWT

The Chevron Wastewater Treatment (WWT) process is a proprietary process developed by Chevron Research Company. Although the process was originally developed to treat sour refinery wastewaters, its developers claim it to be capable of treating sour wastewaters from coal processing and synthetic fuel plants.

The process basically consists of sequentially stripping first acid gases such as hydrogen sulfide and carbon dioxide and next ammonia from a foul water. The stripped ammonia is recovered, concentrated, and washed to yield a high-purity anhydrous ammonia byproduct. In refinery wastewater applications, a high-purity hydrogen sulfide stream is produced and may be fed to a sulfur recovery plant. In other applications, the hydrogen sulfide stream may be diluted by other acid gases such as carbon dioxide, but sulfur recovery may still be feasible.

In the acid gas stripper, hydrogen sulfide and other acid gases are stripped upwards while ammonia and water flow downward, countercurrently to the stripped vapors. A stripped water reflux stream is used to hold ammonia in the wastewater. In the next stripper, ammonia is stripped from the wastewater. The ammonia vapors are subsequently compressed to yield a liquid ammonia byproduct. Depending on the characteristics of the wastewater, pH adjustment may be necessary preceding the ammonia stripper in order to strip fixed ammonia.

The stripped bottoms from the ammonia stripper typically contain less than 5 ppmw hydrogen sulfide and less than 50 ppmw ammonia. The purity of this stream and the acid gas and ammonia streams can be adjusted by changing the operations of the scrubbing and distillation towers. Any carbon dioxide in the wastewater is totally stripped in the acid gas stripper. Removals for other compounds have not been reported.

The acid gas taken from the stripper typically contains less than 50 ppmw ammonia and less than 5000 ppmw water. The purity of this acid gas may be affected by other contaminants in the wastewater feed, but these effects are not discussed in the open literature. Secondary wastes from the Chevron WWT process include the acid gas which exits the first fractionating column, a light flash gas from the degasser, and unspecified waste products from the ammonia scrubber.

As of 1978, the Chevron WWT process had been employed in ten commercial facilities, mainly at refineries. No information is available which indicates its reliability in Lurgi-based synfuels plants.

For Chevron WWT applications in Lurgi-based synfuels plants, a representative capital investment requirement is \$35,000 per m^3/hr for treating 300 m^3/hr of wastewater. This cost estimate includes the costs associated with recovering ammonia as a byproduct, but does not include the costs associated with treating the stripped acid gases.

Inert Gas Stripping

Inert gas stripping involves passing a gas (e.g., air, nitrogen, CO) through a separation tower countercurrent to the wastewater flow. The contact between the gas and liquid phases promotes desorption of the dissolved gases. The vapor phase, containing the stripping gas and NH_3, H_2S, HCN, and CO_2 is then further processed. If air is used as the inert gas, oxidation of organics can occur, as well as oxidation of H_2S to form colloidal sulfur.

Because the carrier gas is generally noncondensible at standard operating conditions, it is frequently difficult to treat the various acid gases in the stripper overhead stream. While this stream has generally been incinerated in the past, the practice is now being phased out because of NO_x and SO_2 emissions limitations.

Although inert gas stripping can be performed at lower temperatures than steam stripping, the added cost of flue gas control and the increased difficulty of byproduct recovery could significantly raise the capital and operating costs. Inert gas stripping is best applied on low flow rate wastewater streams with low NH_3 and CO_2 levels which can be vented. Inert gas stripping removal efficiencies equivalent to those obtained with steam stripping can be obtained when the inlet feed water or stripper feed gas is preheated.

Vacuum Distillation

Vacuum distillation removes dissolved gases from wastewater by lowering the total system pressure. Dissolved gases whose vapor pressures are relatively high tend to leave the liquid phase when their partial pressure in the vapor phase is decreased due to a lowering of the system pressure. In order to prevent excessive amounts of water from vaporizing, the liquid temperature must be fairly low. Some cooling of the sour water stream may be required.

Removal efficiencies equivalent to those achieved with steam stripping are possible with this approach, but generally lower removals are experienced. The high energy costs associated with this technology make this approach noncompetitive in installations where stripping steam is available.

4.2.1.4 Processes for Removal of Dissolved Organics

The most widely used processes for the reduction of dissolved organics, both in industrial and municipal wastewaters, are biological processes. In biological processes, concentrated masses of microorganisms break down organic matter, resulting in the stabilization of the wastewater. The microorganisms can be classified as follows:

Aerobic organisms - require molecular oxygen for metabolism.

Anaerobic organisms - derive energy from organic compounds and function in the absence of oxygen.

Facultative organisms - may function in either an aerobic or anaerobic environment.

Several different processes are available which utilize one or more of the different types of organisms. These processes are potentially applicable to the treatment of a number of Lurgi gasification wastewater streams as long as concentrations of inhibitory compounds are kept low enough not to adversely affect the organisms. The remainder of this section (4.2.1.4) summarizes available information on dissolved organics removal by the following processes:

- Activated Sludge,
- Trickling Filters,
- Rotating Biological Contactors,
- Lagoons, and
- Anaerobic Digestion

Table 4-40 is given as a brief summary of some of the information discussed in the text.

TABLE 4-40. TECHNOLOGIES POTENTIALLY APPLICABLE TO THE REMOVAL OF DISSOLVED ORGANICS FROM LURGI-BASED SYNFUELS PLANT WASTEWATERS

Technology	Technology Principle	Components Removed	Removal Efficiency	Feed Requirements/ Restrictions	Byproducts and Waste	Comments
Activated Sludge	Biological conversion of the carbonaceous organic matter in wastewater to cell tissue and various gaseous end products.	TOC, BOD, COD, and some inorganic pollutants.	Depends on feed stream characteristics, residence time; 60-90% removal of BOD and 80% removal of COD and TOC possible with residence time >12 hours.	Air or oxygen; supplemental nutrients (nitrogen, phosphorus) may be rerequired; feed rate and loading should be relatively constant; inhibitory compounds may need to be diluted	Excess biological sludge and stripped volatile gases.	Widely used to treat a variety of industrial wastes, including coke oven and refinery wastewaters.
Trickling Filters	Same as activated sludge. Bacteria form film on permeable media bed, air blown countercurrent to wastewater flow.	Same as activated sludge.	60-85% of BOD in refinery wastewaters; 40-90% BOD removal, depending on loading.	Dilution may be required to control loading. More resistant to shock loading than activated sludge.	Excess biological sludge and stripped volatile gases.	Use of trickling filters to treat synfuels plant wastewater has not been demonstrated. Often used as a roughing unit before an activated sludge system.
Rotating Biological Contactors	Same as activated sludge. Bacteria form film on rotating plastic disks. Disk rotation also provides oxygen.	Same as activated sludge.	"Oily waste" BOD removal 68-92% "Phenolic waste" (100 mg/L phenol) 99% reduction of phenol.	More resistant to changes in loading than activated sludge.	Excess biological sludge and stripped volatile gases.	Not demonstrated for treatment of synfuels plant wastewaters; have been installed in refineries.
Lagoons	Degradation of organics by the action of aerobic, anaerobic, or facultative bacteria in ponds; settling of suspended solids.	Same as activated sludge plus suspended solids.	BOD removals 60-90% (influent 200-500 mg/L); 10-90% reduction of COD and TSS.	Susceptible to upsets due to changes in wastewater flow, temperature, and composition.	Biological sludge; potential for leaching; volatile gases may be stripped from aerated lagoons.	Lagoons require relatively large land areas and long residence times. Odors may be a problem with facultative and anaerobic lagoons.
Anaerobic Digestion	Degradation of organics by the action of anaerobic bacteria to form (ultimately) CH_4 and CO_2.	Same as activated sludge, plus solids.	Limited data available; for treatment of biological sludge total solids reductions of 33-58% reported.	Required good control over pH, alkalinity, temperature and inhibitory compound concentrations.	Methane, CO_2, and some H_2S, possible; excess sludge.	Currently used primarily to reduce volume of sludge from aerobic treatment processes.

Biological systems for dissolved organics removal can be either single- or multi-stage systems. In multi-stage systems, two or more biological reactors are used in series. The type(s) of biological processes used in multi-stage systems do not necessarily have to be the same in each stage. The main purpose for using multi-stage systems is to treat high strength wastewaters and/or to achieve better performance than is technically feasible in single-stage systems.

Activated Sludge

An activated sludge system consists of two key components: a reactor and a clarifier. Organic-laden wastewater is introduced into the reactor where an aerobic bacterial culture is maintained in a suspension called the mixed liquor. The bacterial culture or sludge converts the organic materials to carbon dioxide, water, metabolic intermediates, and ammonia. The sludge concentration maintained in the reactor is dependent on the desired treatment efficiency and other application-specific factors. Oxygen is supplied to the reactor by aeration with air or an oxygen-enriched stream. A portion of the mixed liquor is continuously passed into a settling tank or clarifier where the sludge is separated from the treated wastewater. A portion of the sludge is recycled to the reactor while the remainder is removed from the system.

Powdered activated carbon can be added to the system to achieve simultaneous biological and physical-chemical treatment of wastewaters in a modified process known as the activated carbon enhanced activated sludge (ACEAS) process. The organisms grow on the carbon, which helps retain organic molecules near the organisms for faster metabolism. Physical adsorption of organics on the activated carbon also helps reduce the impact of shock loadings of inhibitory compounds on the bacteria.

Knowledge about the performance of a commercial-scale activated sludge process in treating wastewaters from Lurgi gasification is currently limited to foreign experience. Data are available from the treatment of wastewaters having similar compositions, such as weak ammonia liquor from byproduct coking operations, and from bench-scale treatability data for wastewaters from other gasification processes. Table 4-41 summarizes these performance data. These data show that activated sludge is effective in reducing phenolic compounds. COD, BOD, and TOC removals vary greatly with the wastewater being treated.

The data in Table 4-41 and other test data on various wastewaters are providing a growing data base for predicting the performance of activated sludge systems with and without oxygen or activated carbon enhancement. Interactions occuring in the activated sludge process are very complex and are not completely understood. Appendix B-10 in the Control Technology Appendices for PCTMs discusses the development of detailed performance models for activated sludge systems. While these models may be useful in understanding proposed systems, they were not used to predict activated sludge effluent compositions and characteristics in this manual. The amount of uncertainty in estimating the flow rates, compositions, and characteristics of wastewaters produced by synfuels plants does not justify using the complex approach of the detailed models in this manual.

In this manual the compositions and characteristics of treated wastewaters from activated sludge systems are estimated based on the information in Table 4-41. Although a range of removal efficiencies are indicated by the data in this table, the single point values listed below were used in this manual.

TABLE 4-41. COMPARATIVE PERFORMANCE DATA FOR ACTIVATED SLUDGE SYSTEMS TREATING WASTEWATERS FROM BYPRODUCT COKING AND VARIOUS SYNFUELS PROCESSES

Process	Wastewater Source	Characterization, mg/L COD	BOD	Phenolics	SCN-	NH_3-N	Org-N	NO_3-N	TOC
Coke Plant[a]	Ammonia Still Effluent	3900-4600	1700-2800	750-1000	280-510	35-92	21-27	<1	
	Biox Effluent	300-410	5-15	0.25-1.4	3-36	23-163	4-8	2-154	———
GFETC[b]	Raw Process Effluent	21,000-30,000	———	3500-6500	80-200	4000-7500	70-140	<2	———
	Pretreated Biox Influent	5380-7130	3000-6700	1090-1730	14-27	130-180	41-45	<2	———
	Biox Effluent	1110-1340	75-230	0.6-1.6	1-3	14-54	17-21	90-280	———
Hygas[c]	Raw Process Effluent	3400-5300	2980	600-900	17-45	2600-4600	———	———	———
	Pretreated Biox Influent	3540-4190	2570-3090	620-940	12-24	136-148	10	<2-4	———
	Biox Effluent	660-890	270-450	0.1-1.9	2-4	87-122	1-8	<2-4	———
Synthane[d]	Raw Process Effluent	22,000	———	3000	31	9500	———	———	9090
	Pretreated Biox Influent	1250-5690	———	175-1205	———	<500	———	———	500-1960
	Biox Effluent	390-2030	———	<1.0-2.5	———	———	———	———	150-850
METC[e]	Raw Process Effluent	———	———	———	———	———	———	———	———
	Pretreated Biox Influent	4800	2290	920	———	250	———	———	2290
	Biox Effluent	820-1600	80-180	2.5-7.7	———	190-220	———	———	250-480
H-Coal[f]	Raw Process Effluent	88,600	52,700	6800	———	14,400	51	———	———
	Pretreated Biox Influent	3070-4180	1890-2600	750-1450	———	68-140	10-24	———	———
	Biox Effluent	310-380	24-36	0.3-9.7	———	40-140	5-13	———	———
Synthetic[g] Coal Conversion Wastewater	Raw Waste	———	———	4650	———	1000	———	———	4600
	Pretreated Influent	5710	3500	———	———	240	———	11	1000
	Biox Effluent	190-1800	5-1000	———	———	210-250	———	2-7	45-200
SRC-I[h] Wastewater	Raw Recycle Process	60,000	16,900	1900	———	17,800	———	———	10,700
	Pretreated Influent	2,000	1200	280	———	———	———	———	680
	Biox Effluent	250	5	1	———	———	———	———	90

[a] Effluent BOD data are for a reactor showing a well nitrified effluent (64).
[b] Raw gasifier effluent from Indian Head lignite. Pretreated for ammonia removal; diluted to 33% strength (65).
[c] Cyclone and quench effluents from Illinois subbituminous. Pretreated for ammonia removal; no dilution (66).
[d] Byproduct water from Montana Rosebud subbituminous. Pretreated for ammonia removal and diluted to ~5 to 6% and ~25% (67).
[e] Pretreated for ammonia removal and diluted to 36-40% strength. These data are from test series c with producer Run 90 wastewater (68).
[f] Foul water from coal liquefaction. Pretreated for sulfide and ammonia removal and diluted to 22% strength (69).
[g] Pretreated by dilution to 25% strength (70).
[h] Pretreated for ammonia and tar acid removal before being diluted to 20% (71).

	Percent Removal		Percent Removal
COD	80	Organic acids	95
BOD$_5$	90	Cyanide	70
TOC	80	Thiocyanate	70
Total Phenol	95	Tar and Oil	70

Ammonia removals are estimated as 13.5 percent (by weight) of the dry biological sludge produced.

The principal waste stream generated by the activated sludge process is the excess sludge produced as a result of the microorganism growth process. The quantity of sludge generated corresponds to the net growth rate of sludge in the reactor. It is concentrated to between 0.5 to 1.2 weight percent solids in the clarifier.

Another potential waste stream is the emission of volatile species from the surface of the reactor. Pretreatment of the wastewater (e.g., by stripping) might be considered to reduce the concentration of volatiles. However, additional volatile organics will be formed during the biodegradation processes.

No data are available for the reliability of the activated sludge process operating on Lurgi wastewaters. Experience from other applications shows that good reliability depends heavily on avoiding sudden variations in the waste strength or flow; maintaining adequate concentrations of nutrients, such as phosphorus and nitrogen; and on providing equipment spares. Monitoring of the process by well trained operators is also required.

For activated sludge applications in Lurgi-based synfuels plants, a representative capital investment is $40,000 per m^3/hr of wastewater flow. This estimate is for treating approximately 300 m^3/hr of wastewater containing 2000 mg/L BOD$_5$.

Trickling Filters

Trickling filters are fixed-film biological treatment units in which the wastewater is percolated or trickled over a bed of highly permeable media to which a biological slime is attached. Oxygen and organic matter are adsorbed at the surface of the slime layer, where aerobic microorganisms degrade the organics. Excess microorganisms are washed off and a new layer begins to grow in its place. A portion of the treated wastewater is recirculated to the trickling filter to provide control over the hydraulic and organic loadings which determine the sloughing characteristics of the slime layer. The recirculated effluent also ensures continuous wetting of the media and serves to dilute high strength wastewaters. If desired, sloughed-off slime can be separated from the effluent in a downstream clarifier.

The medium used for trickling filters is generally a plastic material which can be designed to provide better oxygen transfer and a much greater specific surface area than naturally occurring materials which can also be used. The light-weight plastic medium can also be contained in less-expensive structures.

Typically, trickling filters will remove from 60 to 85 percent of the influent BOD from refinery wastewaters. With extensive treatment, above 90 percent BOD removal has been obtained for phenolic wastewaters. However, with high organic loadings, BOD removal can be as low as 40 percent. No data are available on the use of trickling filters to treat wastewaters from Lurgi gasification facilities or other high strength wastewaters from synfuels facilities.

There are two secondary waste streams associated with the operation of a trickling filter. The first is the air stream which continually flows across the beds. This stream will contain volatile gases stripped from the wastewater and volatile products of the biological degradation process. The second waste stream is the excess slime which must be continuously removed from the reactor. The slime can be separated from the effluent in a conventional clarifier. However, if the trickling filter is used as the first stage of a multi-stage biological treatment system, it may not be necessary to provide for sludge separation between stages.

Biological filters are highly reliable due to their mechanical simplicity and high concentrations of microorganisms that provide resistance to shock loadings. Decreased performance reliability can be experienced in cold weather due to decreased biological activity.

For use of trickling filters to treat low strength wastewaters (influent BOD_5 of about 150 mg/L), the capital investment requirements are essentially constant at $4000 per m^3/hr of wastewater treated. For treating high strength wastewaters, such as those from Lurgi-based synfuel facilities, the unit costs for trickling filters would be expected to be significantly higher. For example, treating a wastewater containing 2000 mg/L BOD_5 could require a ten-fold increase in the wastewater recirculation rate to the trickling filter. For this example then, the capital investment requirement is estimated at over $50,000 per m^3/hr of influent wastewater. In addition, a trickling filter in a high strength application may not be able to achieve the 60 to 85 percent reduction of influent BOD typical of low strength application.

Rotating Biological Contactors

A rotating biological contactor (RBC) is a form of fixed film biological treatment unit similar to a trickling filter. In an RBC the slime layer of microorganisms grows on the surface of disks, 1.8 to 3.7 m in diameter, which are usually constructed of polystyrene or polyvinyl chloride. RBC's may be operated either as aerobic or anaerobic treatment units depending on the fraction of the rotating disk which is submerged in the wastewater. Excess slime is sloughed off by shearing forces created by rotation of the disks.

Data from RBC treatment of Lurgi gasification wastewaters are not available. Results from the treatment of wastes from other industries showed the following results:

- For an oily waste, reductions of BOD from 47 and 375 mg/L in the influent to 15 and 31 mg/L in the effluent were obtained. This corresponds to 68 to 92 percent removal.
- For a phenolic waste containing 100 mg/L of phenol, 99 percent removal of the phenol was achieved.

Results from treatment of refinery wastes show an increase in removal efficiency with increasing influent concentration.

The only secondary wastes from an RBC are the volatile gases released from the surface of the wastewater and the underflow solids (excess slime) from the downstream clarifier. As with trickling filters, if the RBC is used as the initial stage of a multi-stage system, biological sludge may not be generated as a waste stream from the RBC unit.

RBC units are considered to be moderately reliable in the absence of high organic loadings and extreme cold temperatures. They are subject to limitations involving mechanical considerations, shock loadings, inhibitory substances, and oil. Mechanical problems can arise from weight shifts during sloughing or if the water level in the treatment tank drops too low.

RBCs used to treat low strength wastewaters (influent BOD_5 of about 150 mg/L) are estimated to have capital investment requirements of $11,000 per m^3/hr of wastewater treated (over a wide range of flow rates). However, for treating high strength wastewaters, the capital costs would be significantly higher. For treating a wastewater containing 2000 mg/L, capital investment requirements could increase by a factor of 10 or more. Thus, capital costs could be over $100,000 per m^3/hr. The BOD_5 reduction obtainable in high strength applications is unknown. On a percentage basis, however, removal efficiencies are expected to be lower for high strength applications than for low strength applications.

Lagoons

Lagoons, or ponds, are general terms used to describe bodies of water, generally contained in earthen dikes, which are designed for wastewater treatment. Lagoons contribute to wastewater treatment in several ways, including settling of suspended solids (in undisturbed lagoons) and reduction of dissolved organics by biological activity. Lagoons may be classified as aerobic, anaerobic, or facultative depending on the type or types of biological activity occurring in them.

Aerobic lagoons may be further classified as aerobic algal lagoons or aerated lagoons. Aerobic algal lagoons depend on diffusion from the air and the action of algae to provide the oxygen needed by aerobic organisms. They are typically very shallow (up to 0.5 m). They require large land areas and are used most successfully in warm climates. Aerated lagoons receive their oxygen requirement through mechanical aeration. Depths of 1.8 to 6.1 m are commonly used. The contents of aerated lagoons are also kept well mixed by the mechanical agitation. One potential problem with aerated lagoons is the formation foams.

Anaerobic lagoons are generally 2.4 to 6.1 m deep and are characterized by heavy organic loadings. In these lagoons, wastewater degradation occurs by the action of anaerobic bacteria.

Facultative lagoons are the most common type of wastewater treatment lagoon. They range in depth from 0.9 to 2.4 m. The wastewater is acted on by anaerobic organisms at the bottom of the pond, facultative organisms in the middle, and aerobic bacteria near the surface. Oxygen is maintained in the upper level either by algae or by aerators which do not completely mix the contents of the pond.

Contaminant removals by lagoons depend on a number of design and operational variables including pond depth; retention time; wastewater organic loading, temperature, wastewater pH, flow, and composition; and nutrient levels. Treatment times are longer than for other biological processes.

Aerated lagoons are reported to remove from 60 to 90 percent of BOD_5 from wastewaters having influent BOD_5 concentrations of 200 to 500 mg/L; COD removals are reported to be 70 to 90 percent. Total suspended solids (TSS) removals also range from 70 to 90 percent.

Anaerobic lagoons typically remove from 50 to 70 percent of influent BOD_5 depending on loading and retention time. TSS levels may show an increase due to entrained excess sludge. Facultative lagoons are capable of BOD_5 reductions of 75 to 95 percent.

All types of lagoons produce a sludge residue. This sludge accumulates in the bottom of aerated and facultative lagoons and is removed infrequently (typically every 10 to 20 years). Anaerobic lagoons produce less sludge than the other types. Sludge may be continuously removed from aerated and anaerobic lagoons. All lagoons may produce seepage which may ultimately impact ground water. The amount depends on the type (natural or man-made) and condition of the pond liner.

Aerated lagoons may impact the air due to the stripping of volatiles by the air injected into the lagoon. Anaerobic and aerated facultative lagoons may produce odors due to the release of degradation products such as hydrogen sulfide.

Aerated lagoons are typically very reliable. They require little operator expertise. However, they are susceptible to upsets caused by changes in influent temperature, flow, or composition if the influent is not properly dispersed and/or diluted. Anaerobic lagoons are highly reliable when operated in their narrow optimum pH range of 6.8 to 7.2. They are fairly resistant to upsets due to their high loading of microorganisms. Facultative lagoons are also highly reliable.

Estimated capital investment requirements for the various lagoon types treating relatively low strength wastewaters (200 to 600 mg/L BOD_5) are given below. The values shown are for wastewater flows in the range of 100 to 1000 m^3/hr. For treating high strength wastewaters (~2000 mg/L BOD_5), the cost of lagoons would be significantly increased, as indicated below. The performance of lagoons for treating high strength wastewaters is unknown.

	Capital Investment Requirements, $\$/(m^3/hr)$	
Lagoon Type	Low Strength Wastewaters	High Strength Wastewaters
Aerated	900 - 2700	9000 - 27,000
Anaerobic	3800 - 7000	13,000 - 23,000
Facultative		
Warm Climate	11,000 - 19,000	110,000 - 190,000
Cool Climate	5000 - 9000	50,000 - 90,000

Anaerobic Digestion

Anaerobic digestion is a biological treatment process in which organic molecules are converted to methane and carbon dioxide in the absence of oxygen. The process is carried out in special reactors called digestors, of which there are two basic types. In the standard rate digestor the contents are generally unmixed and unheated. This leads to separation of the reactor contents into several layers. From bottom to top these are: digested sludge, an active digestion zone, relatively clear supernatant, undigested scum, and bacteriologically-produced gas. Residence times are typically 30 to 60 days. High-rate digestors are usually completely mixed and heated. The effluent is separated after leaving the reactor into sludge and supernatant phases. Residence times of 15 days or less are typical. Two stage digestion combines a high-rate digestor with a standard rate unit which serves to separate the digested solids from the treated wastewater.

Two commonly used temperature ranges for anaerobic digestion are 303 to 311 K (mesophilic) and 322 to 330 K (thermophilic). The pH range for anaerobic digestion is from 6.6 to 7.6.

Anaerobic digestion is currently used primarily to reduce the volume of sludge from aerobic treatment processes. Total solids reductions of 33 to 58 percent are reported. No data are available for the treatment of Lurgi wastewaters by this process.

Anaerobic digestion produces two secondary waste streams, waste gas and treated sludge. The gas stream, which consists primarily of carbon dioxide and methane, can be combusted to provide process heat. Care must be taken to avoid explosive mixtures with air. The nature of the treated sludge will depend on the characteristics of the waste being treated. The sludge produced in current applications of the technology has been landfilled after dewatering.

Anaerobic digestion is susceptible to upsets caused by changes in wastewater pH, alkalinity, temperature, and toxics concentrations. It can be operated successfully if these variables are well-controlled. It has not been demonstrated for the treatment of Lurgi wastewaters.

4.2.1.5 Processes for Removal of Residual Organics

Previous sections have discussed processes which are applicable to the removal of organics from aqueous streams containing bulk organics (4.2.1.2) as well as somewhat lower concentrations of dissolved organics (4.2.1.4). The present section (4.2.1.5) summarizes available information on processes which generally will be used in a polishing mode for residual organics removal. It should be emphasized that these categories are somewhat arbitrary and that some of the processes discussed previously might be used for the removal of residual organics. An example of this is wet air oxidation.

The remainder of this section summarizes available information on activated carbon adsorption, chemical oxidation, thermal oxidation, and cooling tower oxidation. Table 4-42 provides a brief summary of the information presented in the text.

Activated Carbon Adsorption

Activated carbon adsorption is one of the most widely used methods for removing residual organics from industrial wastewaters. Adsorption operates on the principle that certain species have a higher affinity than others for the sorbent (in this case activated carbon). Wastewater passing through a packed bed of activated carbon is depleted of those species which have an affinity for the carbon, including a number of organics. As the surfaces on and within the pores of the activated carbon become saturated with adsorbed organics, it is necessary to remove this spent carbon and either dispose of it or regenerate it for reuse. For applications in a Lurgi-based synfuel plant, this regeneration will normally be done by thermal processes, the most common of which is thermal oxidation (in a furnace).

TABLE 4-42. TECHNOLOGIES POTENTIALLY APPLICABLE TO THE REMOVAL OF RESIDUAL ORGANICS FROM LURGI-BASED SYNFUELS PLANT WASTEWATERS

Technology	Technology Principle	Components Removed	Removal Efficiency	Feed Requirements/ Restrictions	Byproducts and Waste	Comments
Activated Carbon Adsorption	Adsorption of organics in water by activated carbon; powdered activated carbon has been used in conjunction with biological processes.	Most effective with phenols; some heavy metal removal expected; removals depend on absorptivity of given species and competitions in wastewater.	99% removal for phenols and other readily adsorbed organics, 80% removal for COD.	Adsorbent	Spent adsorbent, regeneration offgases, and backwash.	Probably more effective as a polishing rather than a bulk organics removal process.
Chemical Oxidation	Reaction of organics in wastewater with ozone, peroxides, or chlorine-based oxidants.	TOC, BOD, COD, and oxidizable inorganics.	High removals achievable depending upon conditions of operation.	Oxidant	Most chemical oxidants do not produce secondary wastes; oxidation products depend on dosages.	Chlorine-based oxidants may cause problems with treated wastewater.
Thermal Oxidation (Incineration)	Combustion of organics.	All oxidizable organics.	Essentially complete destruction of organics in properly designed system.	Supplemental fuel, preconcentration will improve performance and lower supplemental fuel requirements.	Flue gases.	An effective process for removing organics but the supplemental fuel requirements may be substantial.
Cooling Tower Oxidation	Air and aerobic oxidation and stripping of organics and dissolved gases.	TOC, COD, BOD, phenols, other organics, and NH_3.	For refinery application, 99+% phenol reductions have been obtained with BOD reduction of 80%.	Sensitive to suspended matter, oils, and high TDS.	Blowdown/drift.	Treated wastewater use in small refinery cooling towers has been practiced.

The performance of activated carbon adsorption in treating specific wastewater streams depends on the nature of the compounds present. Tests are generally conducted to determine the applicability and economics of the process. Tests conducted on streams similar to those expected in Lurgi gasification have shown the results summarized in Table 4-43. The removals given in this table were used as the basis for performance of carbon adsorption systems in this manual. In addition cyanide and thiocyanide removals of 50 percent were used, although some data indicate higher removals may be possible (76).

TABLE 4-43. ACTIVATED CARBON ADSORPTION EFFICIENCIES FOR WASTEWATER SIMILAR TO THOSE EXPECTED FROM SYNFUELS FACILITIES

Component	Removal	Reference
Tars	99%	72
Oils	99%	72
Organic Acids	70%	73
COD	80%	72
BOD	60%	74
TOC	70%	a
Phenols	99.9%	75

[a] Based on adsorption isotherms generated in the laboratory using pretreated gas liquor from Lurgi-type plant in Kosovo, Yugoslavia.

The most important secondary waste streams generated by carbon adsorption are related to the backwashing and regeneration steps. Backwashing of downflow fixed bed adsorbers produces a stream containing high levels of suspended solids since the bed acts like a granular media filter. (A separate filter ahead of the carbon adsorption unit may be required if high levels of suspended solids are present.) Thermal regeneration produces an offgas stream which may contain some unoxidized organics, carbon monoxide, and other pollutants derived from the furnace fuel and the waste material being combusted. The furnace fuel is first burned stoichiometrically to produce CO_2 and H_2O.

These species then react with the organic material which has deposited on (and within) the carbon particles. Oxygen, which would react directly with the carbon, is not desired in these gases.

Solid wastes from this process include ash and carbon fines. If the carbon is not regenerated, the spent carbon would constitute a solid waste.

Granular activated carbon processes are reported to be moderately reliable both mechanically and operationally. Regeneration furnaces are more subject to mechanical failures than many wastewater treatment processes. However, the wide use of activated carbon adsorption is indirect evidence that the process has acceptable reliability. Data are not available for the application of the process to Lurgi aqueous waste streams.

For activated carbon adsorption applications in Lurgi-based synfuels plants, a representative capital investment requirement is $25,000 per m^3/hr of wastewater flow. This estimate is for treating approximately 300 m^3/hr of wastewater and includes the cost of onsite regeneration but does not include the cost of the initial charge of activated carbon.

Chemical Oxidation

Chemical oxidation is the oxidation of wastewater contaminants to produce more environmentally acceptable degradation products such as water and carbonates by reaction with chemical oxidants such as chlorine, chlorine dioxide, ozone, hydrogen peroxide, and potassium permanganate. The choice of oxidant depends on the nature and concentration of the wastewater organics, the potential oxidation products (some of which may potentially be more toxic than the original compounds), and the wastewater flow rate. For example, oxidation of phenolic compounds using chlorine-based oxidants could result in the formation of highly toxic chlorinated phenols.

Simple equipment is required for chemical oxidation, including storage vessels for the chemicals, metering equipment, contacting vessels, and instrumentation for monitoring pH and the degree of completion of oxidation.

Data are not available for the performance of chemical oxidation in the treatment of Lurgi gasification aqueous wastes. Preliminary results of ozonation of aqueous waste from another coal conversion process bench scale facility showed reductions in phenols and polynuclear aromatic hydrocarbons of 95 to 98% with contacting times of 15 minutes or less. Other laboratory tests showed the following removals for an ozone dosage of 325 mg/L and 90 minutes contact time:

	Influent	Removal, %
COD	318	50
BOD_5	142	58
TOC	93	46

Application of chemical oxidation to wastewaters from synthetic fuels facilities have thus far been confined to bench- or pilot-scale studies, so reliability data are lacking for full-scale treatment plants. Mechanical reliability should be quite high, considering the simplicity of the equipment.

The estimated capital investment required for wastewater ozonation at a dosage of 300 mg/L and 60 minutes contact time is approximately $15,000 per m^3/hr of wastewater flow. This cost estimate is for treating approximately 300 m^3/hr of wastewater at the indicated dosage. The costs for ozonation will obviously depend on the COD content of the wastewater treated. For Lurgi applications, significantly higher dosages of ozone could be required unless the wastewater has undergone fairly extensive pretreatment.

Thermal Oxidation

Thermal oxidation or incineration is a high temperature process for the destruction of a variety of organic wastewater contaminants. Some wastewater incinerators only heat water (with no major amount of the water vaporized) and have low energy requirements and low destruction capabilities. The wastewater incinerators which have the greatest destruction capabilities, and the greatest energy requirement, are those which introduce the wastewater directly into the combustion zone (77). For this manual, it is assumed that incinerators treating wastewaters from Lurgi-based synfuels plants would be of the type which introduces the wastewater directly into the combustion zone (Figure 4-8). Also, for this application it is assumed that the combustion flue gases and the vaporized wastewater stream would be exhausted directly into a quench bath. This approach is similar to that proposed for use at the ANG Coal Gasification Company North Dakota Project (now called the Great Plains Gasification Associates project) which will produce SNG using Lurgi technology (78). For applications in this manual, the incinerator quench system is operated such that the offgas temperature is approximately 350 K. The quench system blowdown (which removes wastewater TDS which is not destroyed or does not exit with the offgas) is the treated wastewater stream and has a flow rate essentially equal to the inlet wastewater flow rate. This approach reduces the amount of water vapor which is lost in the quench offgas stream.

Thermal oxidation is capable of achieving essentially complete destruction of a wide range of otherwise difficult-to-treat organics. Test data for pesticide and PCB destruction show over 99.9% destruction. Data are not available for the incineration of Lurgi aqueous wastes. For this manual thermal oxidation is assumed to achieve 99.9% destruction of COD, BOD, TOC, phenol, organic acids, tars, oils, CN^-, SCN^-, NH_3, and H_2S.

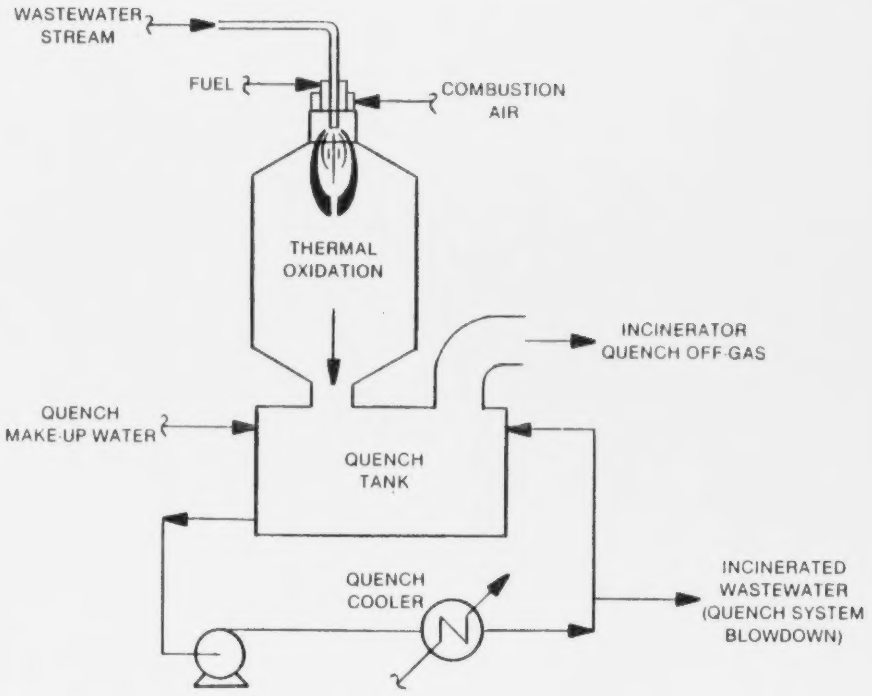

Figure 4-8. Wastewater incinerator with quench

The incinerator quench offgas stream is estimated to have a flow rate of 170 kg mole for each m³ of wastewater treated. This flow rate estimate assumes combustion of oil (such as Lurgi byproduct oil) with 15% excess air and that the quench offgas is saturated with moisture at 75°C. The estimated composition of the quench offgas stream under these conditions is as follows:

N	51 Vol. %
CO_2	9 Vol. %
O_2	1.8 Vol. %
H_2O	39 Vol. %
NO_x	90 ppmv
CO	35 ppmv
Hydrocarbons	10 ppmv
Particulate matter	4 g/Nm³
SO_2	Depends on the fuel sulfur content

The sulfur dioxide content of the offgas will typically be in the range of 150 to 1000 ppmv for liquid fuels with sulfur contents in the range of 0.4 to 2.4 wt. %. Nitrogen oxides in the offgas will depend on the nitrogen content of both the fuel and wastewater, but are expected to be relatively low.

The particulate matter value is the least certain of the values given. The portion of this value which is due to fuel combustion products is estimated to be small (0.15 g/Nm³ or less). The major source of particulate matter is the inorganic portion of the inlet wastewater TDS. The particulate matter content shown (4 g/Nm³) is based on an assumed inlet wastewater TDS of 35,000 mg/L. If all of that TDS entered the offgas stream, the particulate matter content would be around 10 g/Nm³. Part of that inlet TDS is organic and is destroyed by thermal oxidation and part of it is removed by the quench system. It is assumed that 60 percent of the inlet TDS would be removed by these two mechanisms.

Thermal oxidation is widely used to dispose of a variety of industrial organic wastes. Incinerators have been operated for periods exceeding a year without a forced shutdown. Important factors affecting performance reliability are atomization of the waste, location of atomizers with respect to primary combustor, mixing of the waste with combustion air, combustion temperatures, residence time, and excess air flow. In one synfuels application heat recovery was not used because of incinerator/quench system reliability considerations (78).

For thermal oxidation applications in Lurgi-based synfuels plants, a representative capital investment requirement is $180,000 per m^3/hr of wastewater flow. This cost estimate is for treating approximately 30 m^3/hr of wastewater.

Cooling Tower Oxidation

Cooling tower oxidation describes a natural process which occurs when wastewaters with appreciable organics loadings are used as cooling tower makeup. Reactions with oxygen diffusing from the air and the action of bacteria will reduce the concentration of biodegradable organics in the water. The use of cooling tower oxidation has thus far been limited to the concentration of wastewaters containing low levels of easily oxidizable, nonvolatile organics.

Very limited performance data are available for cooling tower oxidation. In one refinery which used biological treatment effluent as cooling tower makeup, reductions in phenolics from 12 mg/L in the influent (makeup water) to 0.09 mg/L in the cooling tower blowdown were reported. BOD_5 reductions of about 80% were also reported.

Data are not available at present for the performance of cooling tower oxidation on Lurgi wastewaters. In wastewater treatment examples presented in Section 4.2.2, wastewaters introduced into the cooling tower are assumed to be concentrated, but no removal of organic constituents is assumed to occur (other than those which leave with the cooling tower drift). This assumption is based on the reasoning that the water has been subjected to strong oxidizing and stripping treatment prior to entering the cooling tower. Thus, the organics present should have a relatively low volatility. The degree of oxidation that will occur with the residual organics in a synfuels wastewater has not been determined.

Ammonia is expected to be stripped in the cooling tower if it is present in the wastewaters used as makeup water. The quantity of ammonia removed is estimated to be ten percent (by mass) of the ammonia in the makeup for each cycle of concentration, i.e., 10 percent for one cycle, 19 percent for two cycles, 27 percent for three cycles, etc. The cycles of concentration predicted for each coal case will vary, depending on the quality and volume of wastewater produced.

While the use of a cooling tower to oxidize organics and reduce wastewater volume in a synfuels plant has some potentially significant advantages, it also presents some potential problems. First, contaminant concentrations different than those encountered in refinery wastewaters can be expected; phenol concentrations, for example, will probably be higher. Associated with this process will be an increased potential for fouling of process heat exchangers by wastewater contaminants such as particulates, inorganics, or biologically-generated solids. The potential for biological fouling of heat transfer surfaces has not been well defined (in data available in the public domain), but may be high due to the presence of organic/inorganic compounds in the cooling water that will support biological growth. Chlorination of cooling water for biological growth control may not be applicable because of the potential to form toxic chlorinated organics; other biocides may need to be used in place of chlorine. Conventional cooling water treatment chemicals for controlling corrosion and scaling may also not be applicable to cooling towers using process wastewaters as makeup due to interferences caused by dissolved organic and inorganic compounds.

Discharge streams from cooling towers include evaporation/drift and blowdown. When treated process wastewaters are used as cooling tower makeup, evaporation and drift will include stripped volatile gases such as ammonia as well as dissolved species present in the water. Cooling tower blowdown will contain the non-volatile, non-degradable makeup water constituents plus water treatment chemicals that are added to the system.

Costs associated with using wastewaters as cooling tower makeup are not available. The economics will depend on savings realized due to reduced plant demands for raw makeup water and on the overall plant wastewater treatment scheme and water balance.

4.2.1.6 Processes for Removal of Dissolved Inorganics

Inorganic compounds may need to be removed from Lurgi gasification plant aqueous wastes in order to meet discharge considerations or to prevent operational problems due to scaling and plugging where these streams are to be recycled/reused in the plant. The degree of inorganics removal that is desired will depend on the water quality requirements of the various end use processes or discharge options.

In general, most inorganic treatment processes are designed to lower the calcium, magnesium, silica, carbonate, and/or sulfate levels in the wastewater. These species form the majority of the compounds which cause plugging, scaling, and fouling when their solubility products are exceeded. Usually dissolved inorganic treatment processes also lower the concentrations of other inorganic compounds such as heavy metals and trace elements. Reductions achieved depend on pH, temperature, reagents used, etc.

Processes discussed in this section include chemical precipitation and ion exchange. Table 4-44 gives a brief overview of the information presented in the text.

Chemical Precipitation

Chemical precipitation is a process which can significantly reduce the concentrations of selected dissolved solids in a wastewater stream. The key to the process is the addition of chemicals which will promote the precipitation of salts containing the components desired to be removed. The precipitated solids can be removed from the treated wastewater by settling and/or flotation.

TABLE 4-44. TECHNOLOGIES POTENTIALLY APPLICABLE TO THE REMOVAL OF DISSOLVED INORGANICS FROM LURGI-BASED SYNFUELS PLANT WASTEWATERS

Technology	Technology Principle	Components Removed	Removal Efficiency	Feed Requirements/ Restrictions	Byproducts and Waste	Comments
Chemical Precipitation	Use of chemical agents to promote the precipitation of inorganic solids from wastewaters.	Ca, Mg, heavy metals, and alkalinity.	Variable depending on constituents. Typical values are 40% removal for Cr, 50% for Ni, and 20% for Cu and Hg.	Lime, polymer, and soda ash may be required. Specific chemicals and dosages based on tests.	Sludge contaminated with heavy metals.	Generally followed by filtration and/or activated carbon adsorption.
Ion Exchange	Substitution of H^+, Na^+, OH^-, or Cl^- ions for other ionic species; exchange resins regenerated with acid, base, or salt solutions.	Heavy metals, F^-, CN^-, and scaling species.	Essentially complete removal for most ions.	Regenerants, replacement resins are needed. Resins can be found by high organic loadings in inlet water.	Spent regenerants and resins.	Most effective as a polishing process. Clearly applicable to boiler feedwater treatment needs. Of limited use in treating process wastewater containing high concentrations of organics or dissolved solids.

The most common use of chemical precipitation is in lime-soda softening. This process lowers hardness (dissolved calcium and magnesium) and adjusts alkalinity by the addition of lime and soda ash in the correct proportions. It is widely used in industry for the treatment of both raw water and wastewater. Figure 4-9 shows a typical industrial lime-soda softening system. Influent wastewater is thoroughly mixed with lime slurry and soda ash which causes the pH to rise (typically to a range of 9.8 to 10.5). Under these conditions, a variety of compounds can exceed their solubility products although the process is most often applied to reduce hardness and alkalinity by precipitating calcium and magnesium hydroxide. The solids that precipitate are frequently finely divided and difficult to dewater. A clarifier is normally used for solids removal, followed by a gravity-flow granular bed filter. The gravity filter effluent will normally need pH adjustment before release to downstream processes. Recycle of the clarifier underflow is used to provide the seed crystals necessary to sustain reasonable precipitation rates. Clarifier underflow blowdown may be further dewatered, if desired, with a device such as a rotary vacuum filter.

Lime-softener performance depends strongly on influent composition, reagent dosages, and equipment configuration. For cold lime-soda softening, effluent calcium hardness is typically 50 mg/L (expressed as $CaCO_3$), and non-sodium alkalinity is typically 35 mg/L (as $CaCO_3$). For cold lime-soda softening, two sets of trace element removal data are:

Element	% Removal	
Cadmium	0	Not reported
Chromium	88	35
Copper	40	50
Mercury	25	Not reported
Nickel	45	40
Lead	2	27
Selenium	33	Not reported
Zinc	71	36

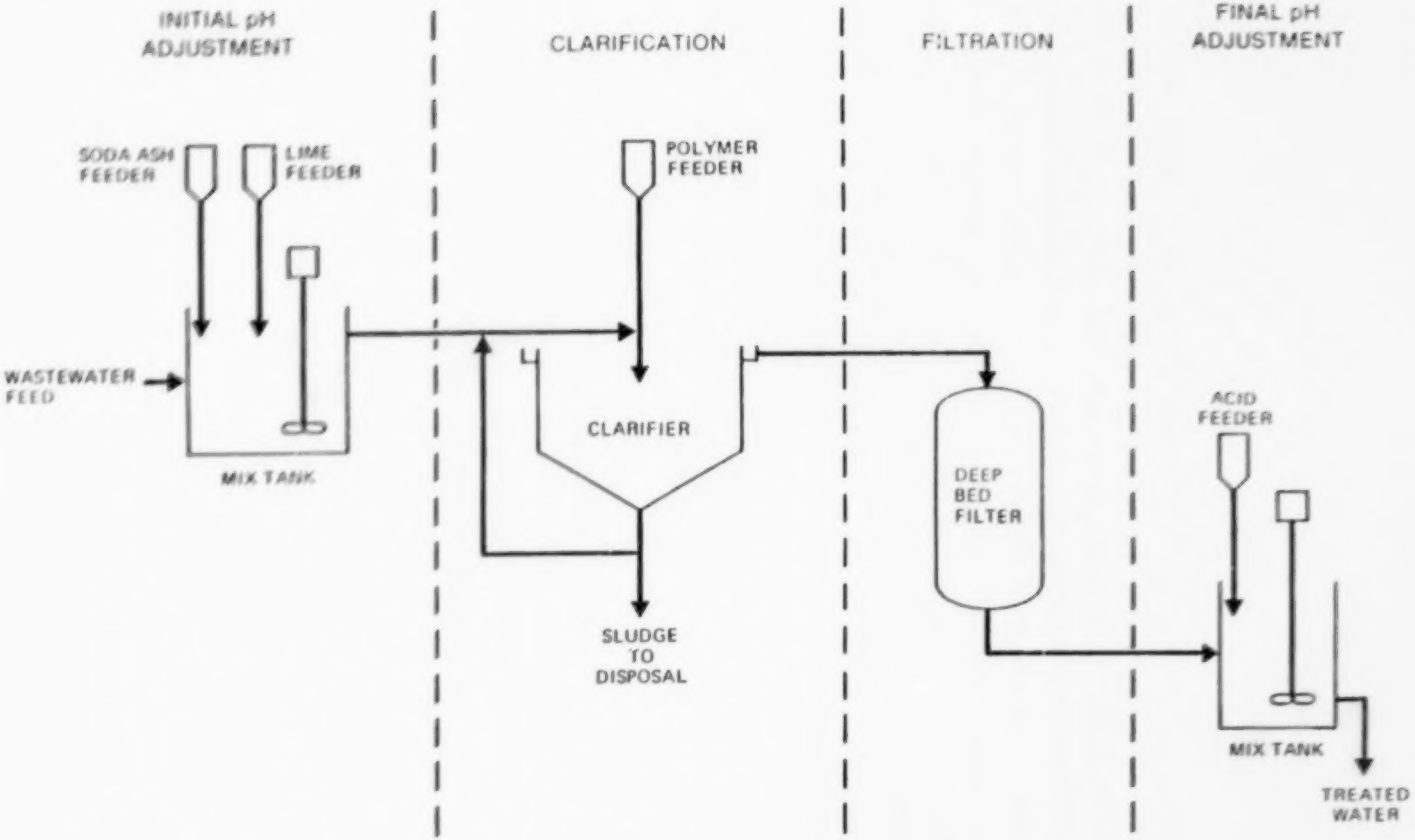

Figure 4-9. Process flow diagram for lime/soda softening system

Trace element concentrations in coal gasification wastewaters are highly dependent on the concentrations of those elements in the coal. Prediction of trace element removals and concentrations within a specific wastewater treatment system requires detailed coal feedstock and treatment system design information. Trace element balances must be determined which account for removals, recycle effects, reactions, and precipitation/scaling tendencies. Since this level of detail is beyond the scope of this manual, the levels of trace elements in treated wastewaters has not been estimated.

This manual does, however, give estimated capital and operating costs for some potential chemical precipitation applications within the Lurgi-based synfuels plants examined. For these example applications, costs are based on the wastewater stream flow rates involved and assumed typical chemical addition requirements.

The major waste produced by chemical precipitation is the precipitated solids stream. For lime/soda softening, the precipitated solids consist primarily of insoluble hydroxide salts. Dewatered sludge from a vacuum filter is estimated to contain 20 weight percent solids.

Lime-soda softening is widely used in industry and is generally very reliable. The equipment used shows a high degree of reliability and is also easily spared. Fluctuations in temperature, flow rate, and reagent dosage can lead to process upsets.

For chemical precipitation applications in Lurgi-based synfuels plants, a representative capital investment requirement is \$6000 per m^3/hr of wastewater flow. This estimate is for treating 300 m^3/hr of wastewater.

Ion Exchange

The ion exchange process involves a reversible interchange of ions in solution with other ionic species bound to a solid ion-exchange medium. Natural and synthetic media are available for the removal of both positive and negative ions. Ion exchange equipment and the operation of the process are similar to activated carbon adsorption in that the wastewater to be treated flows through packed beds of ion exchange media until regeneration is required. In ion exchange, the regenerant is usually a concentrated solution containing the ionic species to be replaced in the resin matrix. The removed species are displaced and may be treated further as desired. Solution pH and the presence of species whose affinity for the given media is greater than that of the species to be removed have an impact on the operation of the process.

A properly designed and operated ion exchange system is capable of producing a very high quality effluent suitable for boiler feedwater makeup (if organics are not present) or for other systems requiring high purity water. The process is reported to be less successful in treating industrial wastewaters than raw water. Irreversible fouling and reduced removal efficiencies have been reported.

Regeneration of the ion exchange media produces the only secondary waste stream from the process. The spent regenerant will contain all the species reversibly adsorbed from the original wastewater, but in higher concentrations. The volume of the stream will depend upon the frequency of regeneration.

Ion exchange has been successfully utilized in water softening, boiler water deionization, and chromate recovery from cooling tower blowdown. Quantitative onstream availability data are not available.

For ion exchange applications in Lurgi-based synfuels plants, a representative capital investment requirement is $36,000 per m^3/hr of wastewater flow. This cost estimate is for treating approximately 300 m^3/hr of wastewater containing 3000 mg/L of total dissolved solids.

4.2.1.7 Processes for Volume Reduction

In order to make the disposal of residual treated aqueous wastes more economical, it may be desirable to reduce their volumetric flow rate. The three processes discussed in this section are designed to provide that reduction. They are:

- Membrane separation,
- Forced evaporation, and
- Cooling tower concentration.

Table 4-45 is a brief summary of the information discussed in the text.

In each of these technologies, a portion of the water is removed from the waste stream, which results in a smaller volume residual stream for disposal. In the process of doing so, however, the concentrations of contaminants remaining in the residual stream are increased. The solubility of the waste components may limit the ultimate volume reduction of the residual stream. Another factor which may potentially limit the use of some of these processes in Lurgi-based synfuels plants is the potential need to extensively pretreat the wastewaters for the removal of contaminants which may cause operating problems.

Membrane Separation

Three membrane processes having potential applicability for aqueous waste treatment are ultrafiltration, reverse osmosis, and electrodialysis. Ultrafiltration and reverse osmosis are very similar processes in that they both achieve separations by applying a pressure gradient across a semipermeable

TABLE 4-45. TECHNOLOGIES POTENTIALLY APPLICABLE TO WASTEWATER VOLUME REDUCTION OF LURGI-BASED SYNFUELS PLANT WASTEWATERS

Technology	Technology Principle	Components Removed	Removal Efficiency	Feed Requirements/ Restrictions	Byproducts and Waste	Comments
Membrane Separation (ultrafiltration, reverse osmosis, and electrodialysis).	Use of semi-permeable membrane and pressure or electric potential to separate water from its dissolved constituents.	Relative rejection efficiencies of the various soluble species will be determined by membrane characteristics and conditions of process operation.	90-95% rejection of of dissolved salts.	Membrane	Spent membrane material and brine.	May be useful as preconcentration step prior to further treatment or ultimate disposal of wastewater. Membrane scaling and fouling with organics may limit the applicability of this technology to the treatment of process condensates.
Forced Evaporation	Thermally induced evaporation of excess wastewater; condensate recovery optional.	All nonvolatile species will remain in brine.		None	Noncondensible gases and waste brine.	Very stringent materials requirements. Process requires significant amounts of energy (either steam or electricity).
Cooling Tower Evaporation	Wastewater used as cooling tower makeup is concentrated by evaporation.	All nonvolatile species will remain in blowdown.	75-80% volume reduction common in conventional cooling towers.	Extensive pretreatment may be required.	Blowdown	Use of process wastewater as cooling tower makeup may require extensive upstream treatment.

membrane. The primary differences between the processes are related mainly to the properties of the membranes. Due to use of larger pore size membranes, ultrafiltration is generally not impeded by osmotic pressure and can therefore be effective at lower operating pressures. In ultrafiltration, which typically operates from 0.17 to 0.79 MPa, solvent molecules (e.g., water) are allowed to pass through the membrane while higher molecular weight impurities are retained. In reverse osmosis, higher pressures, typically up to 7 MPa are used. Water, light aliphatics capable of hydrogen bonding (e.g., alcohols, phenol, amines, etc.), and other nonelectrolytes having molecular weights less than about 200 pass through the membrane while ionic species and heavier organics are rejected.

Electrodialysis removes ionic species from the original stream by the use of alternating cation- and anion-exchange membranes arranged to form a number of solution compartments. Under an electric potential driving force the anions in solution tend to migrate toward the anode while cations tend to move toward the cathode. The alternating ion-exchange membranes result in the depletion of ionic species in half the solution compartments and their concentration in the other half.

Each of these processes is capable of high removal efficiencies of the species which they are designed to remove. All membrane processes are subject to fouling and plugging and thus are applicable only to streams having very low concentrations of suspended solids.

Reverse osmosis is capable of concentrating up to 95 percent of the TDS present in waste streams. Rejection rates for chlorinated hydrocarbons of nearly 100 percent have been reported. Electrodialysis is capable of water recoveries of 80 to 90 percent from wastewaters containing up to 100 mg/L of dissolved organics; the recovered water can contain as little as 3 to 5 mg/L of dissolved solids. Removals of from 50 to greater than 90 percent of ionic compounds from aqueous streams containing from 5,000 to 10,000 mg/L of such compounds are reported.

Membrane processes produce a stream in which the removed species are concentrated and another in which they are depleted. Either stream may be considered a waste depending on the application. In the context of wastewater concentration, the concentrated stream would be considered the waste stream. It may be concentrated further by other processes or disposed of.

The reliability of membrane processes is primarily a function of membrane life, which, in turn, is a function of the nature and extent of fouling and plugging. For most wastes, membrane life must be determined experimentally. No data are available for the reliability of membrane technologies applied to Lurgi wastewaters. However, for the more highly contaminated waste streams which can be produced by a Lurgi-based facility, pretreatment of the wastewater will undoubtedly be required to maintain reliable operation of membrane separation processes.

For reverse osmosis and electrodialysis applications in Lurgi-based synfuels plants, representative capital investment requirements are $8,000 and $11,000 per m^3/hr of wastewater flow, respectively. These costs estimates are for treating approximately 300 m^3/hr of wastewater containing 3000 mg/L of total dissolved solids. Brine disposal costs are not included in the estimates.

Forced Evaporation

Forced evaporation processes are used to reduce the volume of wastewater, and in most cases, to recover the evaporated water. If few organics are present in the inlet wastewater, the recovered water is usually high quality and can be reused after little or no additional treatment. Nonvolatile components in the wastewater are concentrated into a small waste brine.

Many types and arrangements of evaporators are possible for reducing the volume of wastewater and concentrating nonvolatile components. The two principal classes are multi-effect evaporators and vapor compression evaporators. Vapor compression evaporators have lower energy consumption and operating costs than comparable multi-effect evaporators, while multi-effect evaporators typically have lower capital costs. This manual addresses only vapor compression evaporators, mainly because of their lower operating costs and because some designs have special non-scaling features. However, the choice between multi-effect evaporators and vapor compression evaporators can be strongly influenced by the availability of excess low grade steam. In other words, if excess steam is available, multi-effect evaporators will not have an energy disadvantage to vapor compression evaporators. Figure 4-10 is a simplified flow diagram of a vapor compression evaporator.

Scale formation on the evaporation side of the heat transfer surfaces is avoided by preferential precipitation of solids on seed crystals in the slurry. Also, the small temperature difference across the heat transfer surfaces ensures that vaporization will occur at the brine-vapor interface rather than at the brine film-wall interface.

The total solids concentration in the residual brine is maintained at or below a maximum of about 200,000 to 400,000 mg/L by removing a waste brine stream. Wastewater streams containing up to 50,000 mg/L of TDS can be treated by vapor compression evaporation to yield a high purity water product containing TDS levels less than 10 mg/L. Higher TDS levels in the inlet wastewater tend to limit the amount of concentration which can be achieved. Vapor compression evaporation systems are generally designed to recover over 90 percent

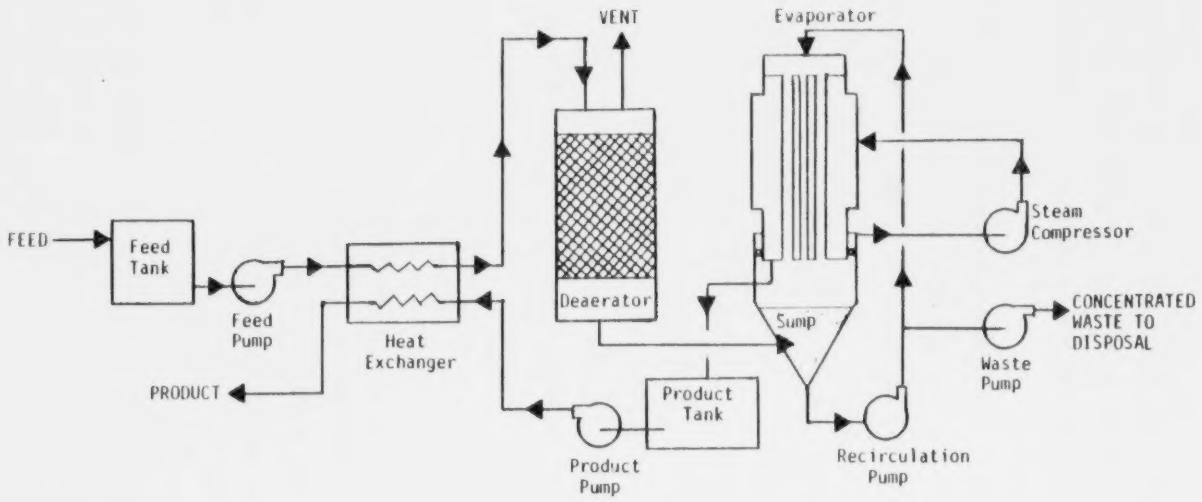

Figure 4-10. Vapor compression evaporation system (79)

of the feed wastewater as product, and recoveries of over 99 percent are possible. For this manual, a maximum concentration of 92 percent has been assumed.

The only significant secondary waste stream produced by forced evaporation is the concentrated brine. This stream will contain all of the nonvolatile components in the inlet wastewater. If the inlet wastewater has been pretreated to remove dissolved gases and volatile species, then the recovered water will be a high quality byproduct stream which can be reused. If dissolved gases and volatile species are in the inlet wastewater, a gaseous secondary waste stream could be produced and/or the recovered water could be contaminated. The composition of the gaseous waste stream obviously depends on the inlet wastewater components. For some applications, the concentrated brine could be further treated via crystallization techniques to produce a solid waste and additional recovered water.

Small compression evaporators were developed about 100 years ago and thousands have been used for desalting seawater (typically shipboard) and brackish water. Hundreds more have been applied in the chemical industries. No specific reliability measures are reported in the open literature. The process uses standard equipment and operations, which tends to indicate adequate reliability.

For vapor compression evaporation applications in Lurgi-based synfuels plants, a representative capital investment requirement is $50,000 per m^3/hr of wastewater flow. This estimate is for treating approximately 300 m^3/hr of wastewater at an overall volume reduction of 92 percent.

Cooling Tower Concentration

When wastewaters are used for cooling tower makeup, two beneficial processes can occur. The first, oxidation of residual organics in the makeup water, was discussed in Section 4.2.1.5. The second is the reduction in waste volume which occurs as a result of the evaporative cooling process. The major incentive for using process wastewaters in cooling towers is the volume reduction which occurs. Concentration increases of 4 to 5 times compared to the inlet water are common for the blowdown from conventional recirculating cooling towers, represening a 75-80 percent volume reduction. This concentrating capability can be effectively used to balance wastewater flows and reduce downstream wastewater treatment costs in a Lurgi gasification facility.

The desire to use treated wastewater as cooling tower makeup may result in the use of more extensive upstream treatment to produce an acceptable quality water for makeup to the cooling system. Also, more expensive cooling water treatment approaches may be necessary to avoid the formation of toxic byproducts (e.g., the formation of chlorinated phenols) or scale, or excessive corrosion in the circulating cooling water. These added costs must be weighed against the cost savings accrued due to decreased demand for cooling tower makeup water or raw water supplies, as well as possible cost savings in downstream treatment processes due to the smaller volume of wastewater to be treated.

4.2.1.8 Disposal Processes

Four processes for the disposal of aqueous wastes are discussed in this section. They are typical of alternatives that may be available at locations across the United States based on current and proposed practices in other industries. They include:

- Surface discharge,
- Deepwell injection,
- Surface impoundment, and
- Codisposal with ash.

Table 4-46 briefly summarizes the information about these processes presented in the following text.

The viability and costs of any of these alternatives depends on a number of site-specific factors, as well as the required level of pretreatment to render the wastewater suitable for disposal.

Surface Discharge

The technical aspects of discharging treated wastewater streams from Lurgi gasification facilities are fairly simple. In particular, the ability of the surface water body to assimilate the pollutants remaining in the treated wastes must be considered carefully before this option can be implemented. It is likely that extended treatment will be desired in order to reduce levels of pollutants such as residual organics and trace metals remaining in many Lurgi wastewater streams prior to surface discharge.

TABLE 4-46. TECHNOLOGIES POTENTIALLY APPLICABLE TO THE DISPOSAL OF RESIDUALS FROM THE TREATMENT OF LURGI-BASED SYNFUELS PLANT WASTEWATERS

Technology	Technology Principle	Components Removed	Removal Efficiency	Feed Requirements/ Restrictions	Byproducts and Waste	Comments
Surface Discharge	Residual waste discharged to a receiving body of surface water.	Entire stream.	100%	Effluent discharge limitations.	None	Exhaustive pretreatment is likely to be required. Disposal technique itself is extremely simple.
Deep Well Injection	Wastes are pumped into subsurface zones where they are isolated from the surface and from potentially useful aquifers.	Entire stream.	100%	Pretreated to remove particulates (>5 μm) and organics to avoid plugging of receiving formation. Volume reduction may be economical.	None	Demonstrated in numerous applications and proposed for several Lurgi-based synfuels plants.
Surface Impoundment	Wastes are placed in a containment basin where all volatile species are evaporated.	All nonvolatile species are left as a residue in impoundment.	100%	Wastewater volatile organic compound concentrations should be low to avoid excessive atmospheric emissions. Volume reduction prior to impoundment may be economical.	Offgases from evaporation of volatile species, residue, and leachate (potentially).	Use of technique limited to locations with available land and net evaporation rates exceeding 0.5 m/year.
Codisposal	Residual wastewater is mixed with gasifier and/or boiler ash for disposal.	Entire stream.	100%	Pretreatment to reduce hazardous contaminant concentrations, and pH adjustment may be desired.	Leachate (potentially); see solid waste disposal discussion.	Use of this technique depends on the effects of residual wastewater contaminants concentrations and their environmental availability.

Deepwell Injection

Deepwell injection is an aqueous waste disposal technique in which the waste is pumped into a suitable subsurface formation via a well. A deepwell disposal system consists of a surface facility for handling and pumping the waste liquid, a specially constructed well or wells, and a subsurface disposal zone.

Some wastes may require pretreatment prior to disposal by deepwell injection in order to remove specific substances from the waste which could plug the disposal zone formation and/or damage equipment. Processes which may potentially be required include oil separation, suspended solids removal, neutralization, heavy metals removal, and/or organics removal.

Injection wells are usually cased and cemented to prevent upward movement of waste fluids. Maximum injection pressures are set by regulations or engineering calculations so as to avoid fracturing of the receiving formation. Operating pressures are set by field tests. Injection zones must be below the deepest underground source of drinking water in the vicinity of the disposal site. Few disposal wells deeper than 1800 meters have been constructed to date due to high costs and because satisfactory disposal zones have usually been found at lesser depths.

A well-designed and controlled deepwell system injecting properly pretreated waste into a suitable receiving formation should be capable of disposing of large volumes of aqueous wastes over a number of years. Deepwell injection requires little surface land and permanently removes the waste from contact with air, surface water, usable groundwater, and the surface of the ground. It may not be a viable option for some locations due to the lack of suitable injection zones and/or if extensive pretreatment is required.

Secondary wastes are not generated by deepwell injection, however, pretreatment prior to disposal may generate secondary wastes.

Deepwell injection has been used to dispose of industrial wastes for over 25 years. Related experience has been provided over an even longer period by the large number of wells injecting oil field brines. Process reliability depends upon careful site selection, proper well completion and casing, and good control over waste pretreatment and pumping pressure.

For deep well applications in Lurgi-based synfuels plants, a representative capital investment requirement is $30,000 per m^3/hr of wastewater. This estimate is for disposing of about 65 m^3/hr of concentrated wastewater in a well 3200 m deep. Flow rates above 65 m^3/hr would require additional wells.

Surface Impoundment

Surface impoundments are widely used in industry to provide for temporary or permanent retention of waste liquids, slurries, and sludges. They are frequently constructed in a natural depression or an artificial excavation with earthen dikes surrounding the impoundment area. They may be lined with a variety of natural or man-made materials including clay, concrete, and thin sheets of various plastics.

Wastewater routed to an impoundment may be discharged or recycled after settling of solids or natural biological degradation, or may be allowed to evaporate in place. Residual sludges or dry solids may be periodically removed for ultimate disposal elsewhere, or the impoundment may be closed with the solids left in place.

If properly designed and operated, surface impoundments should result in minimum environmental contamination. Their use as evaporation ponds will be limited to areas having sufficient net evaporative losses. Their major drawback is the need for relatively large areas of land.

Potential secondary wastes from surface impoundments include volatile contaminants which may be present in the air around the impoundment and leachate. Due to pretreatment, the quantities of air contaminants will probably be small. The quantity of leachate escaping is highly dependent on the nature and integrity of the impoundment liner.

Surface impoundments have been widely used for disposing of various industrial and municipal wastes. When properly designed and operated, potential degradation of groundwater and surface water should be minimized. The major design concern is to minimize the probability for leachate migration through the impoundment liner. The long term integrity of either natural or artificial liners has not been established.

A representative capital investment requirement for disposing of 30 m^3/hr of wastewater is $120,000 per m^3/hr of wastewater flow.

Codisposal with Ash

A potential disposal alternative for treated wastewaters from a Lurgi gasification facility is codisposal with gasifier and/or auxiliary boiler ash. The use of this disposal method is dependent on the effects of the addition of the treated wastewater on overall contaminant concentrations and their leachabilities. Disposal options for solid wastes are discussed in Section 4.3.

4.2.2 Control Applications for Specific Streams Containing Primarily Organic Compounds

Waste streams included in this source type are gas liquor, Rectisol still bottoms, synthesis wastewaters, and secondary wastewater streams from pollution controls. Examples of the application of specific controls to each of these wastewater streams are given in Sections 4.2.2.1 through 4.2.2.4, respectively. Each of the control examples shows the performance of a single treatment step on a specific waste stream.

For each example, the following types of information are given (as available):

- influent and effluent wastewater compositions and flow rates,
- byproduct and secondary wastestream compositions and flow rates,
- capital investment requirements, and
- total annualized costs

Where appropriate, information is provided on the impacts that different coal feed characteristics and/or process changes would have on the example given. The Rosebud coal case is used for each of the examples and any significant differences between that case and the Illinois No. 6 coal case are discussed. The Dunn County lignite case generally has flow rates and compositions which are within the range of the Rosebud/Illinois No. 6 case data.

In Section 4.2.2.5 examples are given of the treatment and ultimate disposal of organic-containing wastewaters in several integrated treatment systems.

4.2.2.1 Gas Liquor (Stream 210)

Gas liquor will be the largest wastewater stream continuously generated in a Lurgi-based synthetic fuels facility. Its flow rate is determined mainly by the moisture content of the raw Lurgi synthesis gas. The gas moisture content in turn is a function of the moisture content of the coal gasified and the quantity of steam (per unit of coal) fed to the gasifier. Higher flow rates of gas liquor are expected when high moisture content coals, such as lignites, are gasified, or when high rank coals requiring high steam rates, such as Illinois No. 6 bituminous coal, are gasified. The flow rates estimated in this manual for the non-SNG synthesis cases are summarized below. For the SNG cases, approximately 5 percent of the raw gas moisture is lost in shift conversion, thus reducing the gas liquor flow rate.

Subbituminous	-	293 m^3/hr
Bituminous	-	495 m^3/hr
Lignite	-	433 m^3/hr

Gas liquor contains a complex mixture of organic pollutants many of which are present in high concentrations. For example, TOC loadings in gas liquor are estimated in this manual to range from 3000 to over 7500 mg/L and BOD_5 to range from 4600 to almost 11,000 mg/L. Phenolic compounds and fatty acids are two classes of organics which have been identified and quantified in gas liquor. Estimated concentrations range from 2300 to 4500 mg/L for phenolics and 200 to 2000 mg/L for fatty acids. In general, the mass loadings of organics in gas liquor are expected to be similar for any coal gasified. However, due to the varying quantities of gas liquor generated, the concentrations of these components can vary significantly. For example, the mass flow rates of phenolic compounds in gas liquor are estimated at 1100 to 1300 kg/hr, but their concentrations range from 2300 to 4500 mg/L.

Gas liquor will also contain high concentrations of dissolved CO_2 and NH_3 as well as lower levels of dissolved H_2S and HCN. The concentrations of the nitrogen- and sulfur-containing gases depend on factors such as nitrogen and sulfur contents of the coal and the gasifier operating conditions. Compared to the levels of organics and dissolved gases, gas liquor contains only minor amounts of dissolved inorganics.

For the reasons discussed above (high flow rate and high pollutant loadings), the treatment of gas liquor will be the most important consideration in the design of the wastewater treatment system in a Lurgi-based synfuel facility. The design of the treatment system will be heavily influenced by the design of the overall facility water system. This in turn will depend on factors such as 1) the availability of plant makeup water (in water-short areas it may be desirable to treat and reuse gas liquor within the plant in order to reduce makeup water requirements), 2) environmental considerations, 3) technical considerations (some processes within the treatment system may require wastewater pretreatment to remove/destroy certain constituents in order to operate effectively and/or reliably, and 4) economic considerations (some processes may be included in order to reduce the size and thus the costs of downstream treatment steps).

Components of the treatment system for gas liquor will likely include processes for removing organics, dissolved gases, and/or dissolved inorganics, as well as wastewater concentration and ultimate disposal techniques. Because of the expected importance of gas liquor to the overall plant treatment system, several examples of applications of control techniques are given in this section (4.2.2.1). Examples of integrated treatment systems for gas liquor (and similar waste streams that likely would be combined with gas liquor for treatment) are presented in Section 4.2.2.5.

Removal of Suspended Solids, Tars, and Oils

Suspended solids, tars, and oils may be removed from wastewater streams by screening, gravity separation, coagulation/flocculation, air flotation, and filtration. In Lurgi-based synfuels plant designs, suspended solids, tars, and oils typically are removed by gravity separation in the gas liquor separation unit. Gravity separation relies upon the different densities of immiscible oil, water, and solids. Although the use of gravity separation for removal of suspended solids, tars, and oils from gas liquor involves the application of a wastewater treatment process to a primary wastewater stream, this example will not be discussed in depth in this section. The gas liquor separation unit in a Lurgi-based synfuels plant is part of the base plant since it is required to upgrade the gas liquor so that a part of it can be recycled to quench the raw Lurgi gas. This process application is mentioned here only to point out the use of this wastewater treatment process on gas liquor in the base plant. In further discussions, the term "gas liquor" refers to the gas liquor stream after it leaves the gas liquor separation unit (this stream is also known as "phenolic water" in some Lurgi synfuels plants).

Removal of Bulk Organics

Solvent extraction and wet air oxidation are processes which may be used to remove bulk organics from Lurgi gas liquor. Solvent extraction has been proven in commercial applications on gas liquor and is the example given here.

Table 4-47 gives the estimated influent and effluent wastewater compositions and flow rates for treating gas liquor by solvent extraction for the Rosebud coal case. The solvent extraction process wastewater flow rates

TABLE 4-47. ESTIMATED REMOVAL OF BULK ORGANICS FROM GAS LIQUOR BY SOLVENT EXTRACTION

	Influent[b]	Estimated Percent Removal	Effluent[c]
Wastewater Flow Rate,[a] (m^3/hr)	293		293
Constituent Compositions[a] (mg/L)			
COD	22,800	46.0	12,320
BOD	10,600	70.9	3,090
TOC	7,640	44.6	4,230
Phenol	4,540	93.6	290
Organic Acids	2,000	15.0	1,700
Tars and Oils	150	66.7	50
CN^- (as HCN)	5		5
SCN^-	6		6
NH_4^+ (as NH_3)	7,610		7,610
Cl^-	25		25
$CO_3^=$ (as CO_2)	13,600		13,600
$S^=$ (as H_2S)	55		55

[a] Flow rates and compositions are calculated values for the Rosebud coal case.
[b] Influent stream is assumed to be gas liquor from the base plant (i.e., after removal of suspended solids, tars, and oils).
[c] A byproduct phenol stream (1330 kg/hr) is also produced.

for the Illinois No. 6 coal case are higher than for the Rosebud coal case (approximately 500 m^3/hr versus about 300 m^3/hr), and the individual stream component concentrations vary due to the different gas liquor composition. For example, the Illinois coal case COD, BOC, and TOC loadings are significantly lower; but CN^-, SCN^-, and Cl^-, levels are higher (see Section 3). Tars and oils in the solvent extraction effluent are assumed to be 50 mg/L for all cases.

The phenolic compounds in most gas liquors are estimated to be approximately 85 percent monohydric phenols and 15 percent polyhydric phenols. Therefore, based on the estimated solvent extraction removal efficiencies of 99.5 percent for monohydric phenols and 60 percent for polyhydric phenols, this example shows an estimated removal of total phenols of 93.6 percent. These recovered phenolic compounds plus recovered oils and organic acids (about 15 percent of the inlet organic acids) comprise the byproduct phenol stream. For this Rosebud coal case example the byproduct phenol rate is 1330 kg/hr. No other significant byproducts or secondary wastestreams are produced from this process.

The application of solvent extraction in this example (Rosebud coal case) is estimated to require a total capital investment of $10.6 millon. Total annualized costs (including capital recovery and byproduct credit) are about $2.7 million per year.

Removal of Dissolved Gases

Processes which may be used to remove dissolved gases from Lurgi gas liquor include steam stripping, PHOSAM-W, Chevron WWT, inert gas stripping, and vacuum distillation. Of these the PHOSAM-W process has been included in several proposed designs and is given here as an example. This example assumes that the gas liquor stream has been pretreated to remove bulk organics.

Table 4-48 gives the influent and effluent wastewater compositions and flow rates associated with the application of a PHOSAM-W process to remove ammonia and other dissolved gases from pretreated Lurgi gas liquor (for the Rosebud coal case). The wastewater compositions shown in Table 4-48 are equivalent to 99+ percent removal of carbonate, 98 percent removal of ammonia and hydrogen sulfide, and 50 percent removal of hydrogen cyanide.

The PHOSAM-W process recovers ammonia as a byproduct and produces an acid gas secondary waste stream (Stream 428) which contains the other removed dissolved gases. The flow rates of these streams are also shown in Table 4-48. For the Rosebud coal case, the acid gas waste stream is approximately (by volume wet basis) 75% CO_2, 0.4% H_2S, and 200 ppmv HCN. The balance is water vapor plus a small amount of residual NH_3. For the Illinois No. 6 coal case the acid gas composition is estimated to be 70% CO_2, 3.4% H_2S, and 0.3% HCN, with the balance being water vapor and residual NH_3.

The total capital investment requirement for the Phosam-W process in this application (Rosebud coal case) is estimated to be $11.8 million while total annualized costs (including capital recovery and by-product credit) are estimated to be $1.5 million per year.

Removal of Dissolved Organics

Dissolved organics could be removed from Lurgi gas liquor by activated sludge, trickling filters, rotating biological contactors, or lagoons.

TABLE 4-48. ESTIMATED REMOVAL OF DISSOLVED GASES FROM GAS LIQUOR BY PHOSAM-W

	Influent[b]	Estimated Percent Removal	Effluent[c]
Wastewater Flow Rate,[a] (m^3/hr)	293		292
Constituent Compositions,[a] (mg/L)			
COD	12,320		12,320
BOD	3,090		3,090
TOC	4,230		4,230
Phenol	290		290
Organic Acids	1,700		1,700
Tars and Oils	50		50
CN^- (as HCN)	5	50	2.5
SCN^-	6		6
NH_4^+ (as NH_3)	7,610	98	150
Cl^-	25		25
$CO_3^=$ (as CO_2)	13,600	99+	1
$S^=$ (as H_2S)	55	98	1

[a] Flow rates and compositions are calculated values for the Rosebud coal case.

[b] Influent stream is assumed to have been pretreated for removal of bulk organics.

[c] Other discharges are byproduct ammonia (2190 kg/hr) and an acid gas secondary waste stream (120 kg mole/hr) containing CO_2, H_2S, HCN, water vapor, and residual ammonia.

The most widely used process to remove dissolved organics is activated sludge and that process is given here as an example for the treatment of gas liquor.

For this example the air activated sludge process will be used, but other variations are available (such as oxygen activated sludge and powdered activated carbon enhancement of activated sludge). Table 4-49 shows the influent and effluent wastewater flow rates and compositions for air activated sludge treatment of pretreated Lurgi gas liquor (for the Rosebud coal case). With the removals shown in Table 4-49, the effluent from the air activated sludge process (Rosebud coal case) is estimated to have COD and BOD loadings of approximately 2500 and 300 mg/L, respectively. For the Illinois No. 6 coal case, these COD and BOD values are about 750 and 90 mg/L, respectively. The Illinois No. 6 case loadings are lower because that case's gas liquor has lower COD and BOD levels.

Biodegradable species such as residual phenols and other organics, ammonia, and cyanides are removed in the activated sludge unit with the efficiencies shown in Table 4-49.

The activated sludge unit for this example produces a secondary waste stream of biological oxidation sludge (Stream 431). This stream has a flow rate of 1620 kg/hr and is approximately 20 weight percent solids (after dewatering).

The total capital investment for activated sludge treatment of the Rosebud case gas liquor stream is estimated to be $14 million. Total annualized costs (including capital recovery) are estimated to be $2.9 million per year. For the Illinois No. 6 coal case, these two costs are estimated to be $10.8 million and 2.2 million per year for total capital and total

TABLE 4-49. ESTIMATED REMOVAL OF DISSOLVED ORGANICS FROM GAS LIQUOR BY ACTIVATED SLUDGE

	Influent[b]	Estimated Percent Removal	Effluent[c]
Wastewater Flow Rate,[a] (m^3/hr)	292		291
Constituent Compositions,[a] (mg/L)			
COD	12,320	80	2,460
BOD	3,090	90	310
TOC	4,230	80	850
Phenol	290	95	15
Organic Acids	1,700	95	85
Tars and Oils	50	70	15
CN^- (as HCN)	2.5	70	0.75
SCN^-	6	70	1.8
NH_4^+ (as NH_3)	150[d]	d	5[d]
Cl^-	25		25
$S^=$ (as H_2S)	1		1

[a] Flow rates and compositions are calculated values for the Rosebud coal case.

[b] Influent stream is assumed to have been pretreated for bulk organics and dissolved gases removal.

[c] A secondary waste stream of biological oxidation sludge (1620 kg/hr) is also produced.

[d] Supplemental ammonia is added to supply nutrient to the organisms for the Rosebud coal case.

annualized costs, respectively. The lower values for the Illinois coal case result from the lower total BOD_5 loading associated with gas liquor from Illinois No. 6 coal.

Removal of Residual Organics

Residual organics may be removed from Lurgi gas liquor by activated carbon adsorption, chemical oxidation, thermal oxidation, and cooling tower oxidation. In this section examples will be given of the application of activated carbon, thermal oxidation, and cooling tower oxidation to gas liquor from Rosebud coal. These examples assume that the gas liquor has been pretreated by removal of bulk organics, dissolved gases, and dissolved organics.

Removal of residual organics by activated carbon adsorption--Activated carbon may be used to adsorb residual organics and other species from pretreated gas liquor. Table 4-50 gives the estimated influent and effluent wastewater flow rates and compositions for treating gas liquor from Rosebud coal by activated carbon adsorption.

The adsorbed constituents accumulate in the carbon bed and must be removed periodically either by replacement or thermal regeneration of the carbon; carbon replacement is normally limited to smaller installations where the carbon is supplied in disposable or returnable containers. For this application (Lurgi gas liquor), onsite regeneration would be more economical, and therefore, secondary waste streams of regeneration flue gas (Stream 436) and carbon fines or char from oxidation of the adsorbed organics would be produced. The carbon fines and char are produced in small amounts and would normally remain in the bed and eventually be removed along with the spent carbon (Stream 435). The regeneration process produces an offgas stream

TABLE 4-50. ESTIMATED REMOVAL OF RESIDUAL ORGANICS FROM GAS LIQUOR BY ACTIVATED CARBON ADSORPTION

	Influent[b]	Estimated Percent Removal	Effluent[c]
Wastewater Flow Rate,[a] (m^3/hr)	291		291
Constituent Compositions,[a] (mg/L)			
COD	2,460	80	490
BOD	310	60	120
TOC	850	70	250
Phenol	15	99.9	0.01
Organic Acids	85	70	26
Tars and Oils	15	99	0.15
CN^- (as HCN)	0.75	50	0.38
SCN^-	1.8	50	0.9
NH_4^+ (as NH_3)	5		5
Cl^-	25		25
$S^=$ (as H_2S)	1		1

[a] Flow rates and compositions are calculated values for the Rosebud coal case.

[b] Influent stream is assumed to have been pretreated for bulk organics, dissolved gases, and dissolved organics removal.

[c] Secondary wastestreams produced are an intermittent carbon regeneration offgas stream (about 180 kg mole/hr average) and a minimal amount of spent carbon.

containing some carbon monoxide and any sulfur species that are in the regenerator fuel. NO_x emissions from this stream are not expected to be significant. Control measures for this stream are discussed in Section 4.1.

For this example, (Rosebud coal case) the estimated total capital cost is $4.6 million. Total annualized costs are estimated to be $1.6 million per year.

Removal of residual organics by thermal oxidation--One method of removing residual organics from gas liquor is thermal oxidation (incineration). The example given here assumes that for economic reasons the wastewater has been concentrated prior to incineration. Table 4-51 gives the estimated influent and effluent flow rates and compositions for the incineration of pretreated gas liquor. The effluent composition corresponds to 99.9 percent destruction of thermally oxidizable constituents. Thermal oxidation is capable of 99.96 to 99.99 percent destruction of many organic compounds (such as DDT, chlordane, and PCBs). Therefore the actual removals may be higher than the 99.9 percent value shown in this example.

The only secondary waste stream produced is the wastewater incinerator quench offgas (Stream 440). The composition of this stream was estimated using emission factors for oil combustion (45) and an assumed combustion of Lurgi byproduct oil (0.5 wt percent sulfur) with 15 percent excess combustion air. Particulate emissions were estimated assuming 40 percent of the TDS in the inlet wastewater appears as particulates in the quench offgas. For this case a total flow rate of 4000 kg-moles/hr is estimated with the following concentrations of pollutants: 200 ppmv SO_2; 90 ppmv NO_x; 35 ppmv CO; 10 ppmv hydrocarbons; and 4 g/Nm^3 particulate matter. For this example, 23 m^3/hr of quench make-up water is required.

TABLE 4-51. ESTIMATED REMOVAL OF RESIDUAL ORGANICS FROM GAS LIQUOR BY THERMAL OXIDATION

	Influent[b]	Estimated Percent Removal	Effluent[c]
Wastewater Flow Rate,[a] (m^3/hr)	23		23
Constituent Compositions, (mg/L)			
COD	30,800	99.9	31
BOD	3,860	99.9	3.9
TOC	10,600	99.9	11
Phenol	180	99.9	0.18
Organic Acids	1,060	99.9	1.1
Tars and Oils	190	99.9	0.19
CN^- (as HCN)	9.4	99.9	0.01
SCN^-	23	99.9	0.02
NH_4^+ (as NH_3)	63	99.9	0.06
Cl^-	310		310
$S^=$ (as H_2S)	13	99.9	0.01

[a] Flow rates and compositions are calculated values for the Rosebud coal case.

[b] Influent stream is assumed to have been pretreated for bulk organics, dissolved gases, and dissolved organics removal and to have been concentrated.

[c] An incinerator quench offgas secondary waste stream is produced (4000 kg mole/hr).

Thermal oxidation of this stream (Rosebud coal case) is estimated to require a capital investment of $5.0 million, while total annualized costs (including capital recovery) are estimated to be 5.8 million per year.

Removal of residual organics by cooling tower oxidation--Although cooling towers have been successfully used in several industrial applications to remove residual organics, ammonia is the only constituent assumed to be removed (stripped) in the cooling tower (other than the small amount of all constituents that are lost in the cooling tower drift). All other constituents are assumed to be retained in the recirculating cooling water and hence appear in the cooling tower blowdown. Because of the loss of water due to evaporation, the concentrations of dissolved constituents in cooling tower blowdown are greater than in the inlet makeup water. Table 4-52 shows the influent and effluent wastewater flows and compositions for using pretreated Lurgi gas liquor from Rosebud coal as cooling tower makeup.

Stripping of ammonia in the cooling tower is estimated to be ten percent (by mass) for each cycle of concentration. For this Rosebud coal example, the cooling tower is assumed to be operating at approximately 10 cycles of concentration. The ammonia concentration in the effluent (blowdown) would have been approximately 50 mg/L if no stripping had occurred.

Secondary waste streams produced are cooling tower evaporation (270,000 kg water/hr) and drift (1900 kg/hr) (Stream 306). The evaporation stream will contain most of the ammonia which is removed unless organics are biologically destroyed in the cooling tower. In that instance some of the ammonia will be consumed by the biological oxidation process.

TABLE 4-52. ESTIMATED COMPOSITIONS FOR USE OF TREATED GAS LIQUOR AS COOLING TOWER MAKEUP

	Influent[b] (Makeup)	Effluent[c] (Blowdown)
Wastewater Flow Rate,[a] (m^3/hr)	291	28
Constituent Compositions,[a] (mg/L)		
COD	2,460	24,000
BOD	310	3,000
TOC	850	8,200
Phenol	15	140
Organic Acids	85	830
Tars and Oils	15	150
CN^- (as HCN)	0.75	7.3
SCN^-	1.8	18
NH_4^+ (as NH_3)	5	17
Cl^-	25	240
$S^=$(as H_2S)	1	9.7

[a] Flow rates and compositions are calculated values for the Rosebud coal case and assumed cooling tower operation at 10 cycles of concentration.

[b] Influent stream is assumed to have been pretreated for removal of bulk organics, dissolved gases, and dissolved organics. For this example, 8,600 kg/hr of additional makeup water is required.

[c] Secondary waste streams produced are evaporation (270,000 kg water/hr) and drift (1900 kg/hr).

The costs of using cooling tower oxidation/concentration have not been estimated in this manual due to the highly site-specific factors involved.

Removal of Dissolved Inorganics

Processes which could be used to remove dissolved inorganics from Lurgi gas liquor include chemical precipitation and ion exchange. The example given in this section is the use of chemical precipitation. This example assumes that the gas liquor stream has been pretreated to remove bulk organics, dissolved gases, and dissolved organics.

Chemical precipitation is effective in reducing the concentrations of a number of dissolved inorganics which contribute to the hardness, alkalinity, and total dissolved solids contents of waters. This treatment process is also capable of reducing trace element concentrations. Since inadequate data are available on the dissolved inorganics present in Lurgi gas liquors, effluent composition from chemical precipitation treatment cannot be estimated.

For the Rosebud coal case, the pretreated gas liquor that might be treated by chemical precipitation would have a flow rate of about 290 m^3/hr. Assuming chemical dosages as listed below, the total capital investment for chemical precipitation treatment is estimated to be $1.8 million. Total annualized costs (including capital recovery) are estimated to be $530,000 per year.

Reagent	Dosage (g/m^3)
93 % hydrated lime	127
Soda ash	65
Polymer flocculant	2
Sulfuric acid	61

The only secondary waste stream produced by chemical precipitation is the precipitation sludge (Stream 433). This material consists mainly of carbonates and hydroxides and is estimated to be produced at the rate of 0.35 kg (dry basis) per m^3 of wastewater treated. For this example, the chemical precipitation sludge flow rate is about 510 kg/hr assuming it is dewatered to 20 percent solids.

Volume Reduction

Volume reduction of Lurgi gas liquor may be achieved by membrane separation, forced evaporation, or cooling tower concentration. The use of the cooling tower to oxidize/concentrate Lurgi gas liquor was discussed earlier in this section. The example given here is for forced evaporation of Lurgi gas liquor for the Rosebud coal case.

Table 4-53 gives the influent and effluent wastewater compositions and flow rates for reducing the volume of Lurgi gas liquor by forced evaporation. The flow rates and concentrations shown in the table are equal to a 92 percent recovery of influent water. This recovery results in a 12.5 times concentration increase in the brine effluent and a recovered water stream of 270 m^3/hr.

The estimated total capital investment for this application of forced evaporation is $16 million. The estimated total annualized costs (including capital recovery) are $4.8 million per year.

Residual Disposal

Four methods of residual disposal are discussed in this manual: discharge to surface waters, deepwell injection, surface impoundment, and

TABLE 4-53. ESTIMATED REDUCTION OF GAS LIQUOR VOLUME BY FORCED EVAPORATION

	Influent[b]	Effluent[c]
Wastewater Flow Rate,[a] (m^3/hr)	291	23
Constituent Compositions,[a] (mg/L)		
COD	2,460	31,000
BOD	310	3,900
TOC	850	11,000
Phenol	15	180
Organic Acids	85	1,100
Tars and Oils	15	190
CN^- (as HCN)	0.75	9.4
SCN^-	1.8	23
NH_4^+ (as NH_3)	5	63
Cl^-	25	310
$S^=$ (as H_2S)	1	12.5

[a] Flow rates and compositions are calculated values for the Rosebud coal case.
[b] Influent stream is assumed to have been pretreated for bulk organics, dissolved gases, and dissolved organics.
[c] Effluent concentrations are 12.5 times influent concentration. Ninety-two percent of the inlet water is recovered as reusable water (270 m^3/hr).

codisposal with ash. Two of these methods -- discharge and codisposal -- involve no additional costs or equipment beyond pretreatment needs. This section gives examples of residual disposal of pretreated Lurgi gas liquor (for the Rosebud coal case) by deepwell injection and by surface impoundment.

Residual disposal by deepwell injection--Table 4-54 gives the estimated flow rate and composition of pretreated gas liquor which could be disposed by deepwell injection. This example assumes that the gas liquor has been pretreated for removal of bulk organics, dissolved gases, dissolved organics, and residual organics. For economic reasons, the gas liquor stream is also assumed to have been concentrated. This method provides for complete disposal of the gas liquor residual with no byproducts or secondary waste streams produced. The estimated total capital investment for deepwell disposal of gas liquor in this example is $1.9 million. Total annualized costs (including capital recovery) are estimated to be $430,000 per year.

Residual disposal by surface impoundment--Table 4-55 gives the estimated flow rate and composition of pretreated gas liquor which could be disposed of in a surface impoundment (evaporation pond). Assumed pretreatment steps are removal of bulk organics, dissolved gases, and dissolved organics plus wastewater concentration.

This disposal method results in two potential secondary waste streams: evaporation losses from the surface of the pond and any leachate which may escape through the natural or artificial liner. These streams have not been quantified for this example, but the evaporative losses will be essentially the water content of the wastewater stream plus any volatile components.

Total capital investment for this example is estimated to be $3.6 million. Total annualized costs (including capital recovery) are estimated to be $770,000 per year.

TABLE 4-54. ESTIMATED COMPOSITION OF PRETREATED GAS LIQUOR FOR DISPOSAL BY DEEPWELL INJECTION

	Deepwell Injection[b]
Wastewater Flow Rate,[a] (m^3/hr)	23
Constituent Compositions,[a] (mg/L)	
COD	31
BOD	3.9
TOC	11
Phenol	0.18
Organic Acids	1.1
Tars and Oils	0.19
CN^- (as HCN)	0.01
SCN^-	0.02
NH_4^+ (as NH_3)	0.06
Cl^-	310
$S^=$ (as H_2S)	12.5

[a] Flow rate and compositions are calculated values for the Rosebud coal case.

[b] Stream is assumed to have been pretreated by removal of bulk organics, dissolved gases, dissolved organics, and residual organics and to have been concentrated.

TABLE 4-55. ESTIMATED COMPOSITION OF PRETREATED GAS LIQUOR FOR DISPOSAL BY SURFACE IMPOUNDMENT

	To Surface Impoundment[b]
Wastewater Flow Rate,[a] (m^3/hr)	28
Constituent Compositions,[a] (mg/L)	
COD	24,000
BOD	3,000
TOC	8,200
Phenol	140
Organic Acids	830
Tars and Oils	150
CN^- (as HCN)	7.3
SCN^-	18
NH_4^+ (as NH_3)	17
Cl^-	240
$S^=$ (as H_2S)	9.7

[a] Flow rates and compositions are calculated values for the Rosebud coal case.

[b] Influent stream is assumed to have been pretreated by removal of bulk organics, dissolved gases, and dissolved organics and to have been concentrated.

4.2.2.2 Rectisol Still Bottoms

Rectisol still bottoms will contain a variety of contaminants including ammonia, cyanide, sulfide, chloride, and organics at relatively low concentrations. The organics present in this stream will mainly be methanol which is used as a solvent in the Rectisol process. The low flow rate of Rectisol still bottoms (10 to 12 m^3/hr) will make it economically unattractive to treat it in a dedicated treatment system. The contaminants present in this stream are also present in Lurgi gas liquor. Thus, blending and treating it with gas liquor is a logical approach, especially since its flow rate is only about three percent of the gas liquor flow.

Rectisol still bottoms do not contain high enough concentrations of organics or dissolved gas to warrant treatment by solvent extraction or ammonia stripping. So, blending of Rectisol still bottoms with extracted and stripped gas liquor is appropriate. Combination of the streams at this point would minimize the treatment costs of the still bottoms stream and take advantage of the economies of scale associated with a relatively small increase in the size of gas liquor treatment facilities.

4.2.2.3 Synthesis Wastewaters

In the Fischer-Tropsch, methanol, and Mobil M-Gasoline syntheses processes, water is produced as a byproduct of the liquefaction reactions and removed from the liquefaction products during the purification and upgrading processes. These wastewaters contain high concentrations of organic contaminants. However, the low concentrations of dissolved gases, dissolved inorganics, and suspended matter would enhance the reuse potential of this wastewater after treatment for organics removal. Where reuse of this wastewater is a priority, treatment in separate facilities to avoid contamination from other wastewater streams may be considered. However, in most facilities this wastewater will probably be combined with other organic containing wastewaters for treatment.

The organic acids, ketones, and aliphatic and ring compounds found in these synthesis process wastewaters are expected to be readily biodegradable. Treatment of these wastewaters in separate facilities by biological oxidation will require consideration of two critical factors: 1) nutrient requirements of biological organisms and 2) influent organic concentrations. Since these wastewater streams will contain little or no dissolved inorganic material, supplemental phosphorus, nitrogen, and traces of other compounds will need to be added to maintain a healthy biomass and ensure effective treatment. The second factor to be considered in treating these wastewaters is the organic concentration/loading on the treatment unit. Treatment of synthesis process wastewaters directly could seriously overload the system and cause a treatment failure. Therefore, dilution of these wastewaters into a range that would be compatible with the biological treatment unit would be required. To maintain an influent BOD of 2500 to 3000 mg/L, F-T synthesis wastewater (about 70 to 75 m^3/hr) must be diluted, depending on coal type, by a factor of 2 to 3.

Mobil M synthesis wastewater (about 55 to 60 m^3/hr) would have to be diluted by a factor of three to four depending on coal type. Similarly, methanol synthesis waste water (about 1 to 5 m^3/hr) would have to be diluted from six to 20 times depending on coal type. The Illinois No. 6 case methanol synthesis wastewater would require the greatest dilution (20 to 1), but it is also the smallest flow rate (1.4 m^3/hr). Dilution of these wastewaters would require an equalization pond upstream of the biological treatment unit. Oversizing a system to handle the larger diluted flow will dramatically increase the treatment costs of this stream.

Two examples have been developed to illustrate the application of specific treatment technologies to these synthesis wastewater streams. These examples are based on treating F-T wastewater but are representative of treating F-T, methanol, and Mobil M wastewaters.

Table 4-56 gives the estimated influent and effluent wastewater flow rates and compositions for treating F-T synthesis wastewater (Rosebud coal case) in an activated sludge unit. The total capital investment requirement for this treatment step is estimated to be $12 million. Total annualized costs are estimated to be $2.5 million per year. These costs are similar to those given earlier for treating Rosebud gas liquor, a much larger volume stream.

Table 4-57 gives the estimated influent and effluent wastewater flow rates and compositions for removing residual organics from pretreated F-T synthesis wastewater by activated carbon adsorption. The estimated total capital investment required for this treatment is $2.2 million and the estimated total annualized costs are $670,000 per year.

TABLE 4-56. ESTIMATED REMOVAL OF DISSOLVED ORGANICS FROM F-T SYNTHESIS WASTEWATER BY ACTIVATED SLUDGE

	Influent	Estimated Percent Removal	Effluent[b]
Wastewater Flow Rate,[a] (m^3/hr)	76		75
Constituent Compositions,[a] (mg/L)			
COD	11,000	80.0	2,300
BOD	8,000	90.0	800
TOC	4,300	80.0	860
Organic Acids	11,000	95.0	540
NH_4^+ (as NH_3)	0	c	5

[a] Flow rates and compositions are calculated values for the Rosebud coal case.
[b] A secondary waste stream of biological oxidation sludge (1100 kg/hr) is also produced.
[c] Supplemental ammonia is added to supply nutrients to the organisms.

TABLE 4-57. ESTIMATED REMOVAL OF RESIDUAL ORGANICS FROM F-T SYNTHESIS WASTEWATER BY ACTIVATED CARBON ADSORPTION

	Influent[b]	Estimated Percent Removal	Effluent[c]
Wastewater Flow Rate,[a] (m^3/hr)	75		75
Constituent Compositions,[a] (mg/L)			
COD	2,300	80	460
BOD	800	60	320
TOC	860	70	260
Organic Acids	540	70	160
NH_4^+ (as NH_3)	5		5

[a] Flow rates and compositions are calculated values for the Rosebud coal case.
[b] Influent stream is assumed to have been pretreated by removal of dissolved organics.
[c] Secondary waste streams of regeneration offgas and spent carbon are also produced. Both have small and intermittent flow rates.

4.2.2.4 Secondary Wastewater Streams

There are two types of potential secondary wastewater streams which will contain primarily organic, reduced sulfur, and/or reduced nitrogen compounds. These streams are condensates from tail gas treatment units used to remove residual sulfur species from acid gas waste streams and scrubber blowdown streams such as the blowdown from the coal lockhopper vent gas scrubber.

Beavon and SCOT Condensates

The Beavon and SCOT processes are examples of processes which might be used to remove residual sulfur from acid gas streams in a Lurgi-based synfuels plant (see Section 4.1). Both of these processes produce a small sour water blowdown from water scrubber/cooler towers. These condensates will have a flow rate of approximately 4 m^3/hr and will contain about 100 mg/L H_2S and 5000 mg/L NH_3. Other pollutant species are not expected to be present in significant amounts.

For this manual, it is expected that a stream of this type and size would be combined with gas liquor upstream of the dissolved gas removal step. No other treatment options have been examined for purposes of this manual.

Scrubber Blowdown Streams

The coal lockhopper vent gas scrubber blowdown stream is used as the basis for example treatment approaches for this type of stream. The composition of this blowdown stream will vary with the lockhopper vent gas composition. The vent gas composition, in turn, will depend on the method used to pressurize the lockhopper. If Lurgi gas is used to pressurize the lockhopper, the scrubber blowdown will contain similar contaminants to those found in the raw gas. If an inert gas is used, the scrubber blowdown will be contaminated mainly with particulate matter, although some raw gas components may also be present. The treatment route employed will vary with the blowdown composition.

Because the contaminants present in this stream will be so similar to those found in Lurgi gas liquor, it is assumed that this stream would be routed to the gas liquor separation unit. This treatment approach will have a negligible impact upon the costs of gas liquor treatment.

4.2.2.5 Integrated Control Examples for Streams Containing Primarily Organic Compounds

The previous portions of Section 4.2.2 illustrated the application of individual wastewater treatment technologies to specific organic-laden streams. In practice, determining which treatment processes should be applied to which wastewater streams and in which sequence depends on numerous factors. Developing a wastewater management plan is a detailed process requiring many site-specific inputs and economic and technical evaluations. It is not within the scope of this manual to develop wastewater management plans for Lurgi-based synfuels plants. However, it is felt that presenting some examples of the sequential application of controls can aid users of this manual. These examples, some of which have features similar to publicly-available proposed treatment schemes in Lurgi-based synfuels plants, illustrate a few of the possible integrations of treatment technologies and residual disposal options.

To a large extent, a wastewater management plan is driven by the residual disposal options available at the plant site. For this manual, four basic methods of residual disposal are assumed to be potentially applicable to U.S. synfuels plants:

- discharge to surface waters,
- subsurface discharge via deepwell injection,
- surface impoundment (evaporation pond), and
- codisposal with gasifier and/or boiler ash.

Deepwell injection and surface impoundment produce no significant discharges to the environment other than the loss of water vapor and possibly some volatile compounds and leachates from surface impoundments. These technologies were discussed in Sections 4.2.1.8 and 4.2.2.1.

Discharge to surface waters requires that the discharged waters be treated sufficiently to meet all local, state, and federal requirements concerning the quantity and quality of the discharge. The integrated control example given here for discharge to surface waters is a system which produces a final effluent which would need to be compared to any site-specific requirements. Ultimately this determination will have to be made for each synfuels plant and plant site.

The integrated control examples for codisposal with ash are options which use treated wastewaters for ash quenching. For these cases, the wastewater residual is used to moisturize the ash and is disposed of along with the ash. Although only one residual disposal method is shown here in each integrated example, in practice two or more techniques could be used at a given plant site. For example, a portion of the treated residual could be codisposed with ash while the remaining portion could be deepwell injected.

For each of the integrated control examples given in this section, the following information will be given:

- Description and block flow diagram,
- Influent and effluent compositions and flow rates,
- Secondary waste streams and byproducts generated, and
- Total capital investment and total annualized costs.

Integrated Control Example No. 1

An example of an integrated treatment scheme for wastewaters containing primarily organic compounds is illustrated in Figure 4-11. As shown, gas liquor is treated by solvent extraction for bulk organics removal and by the

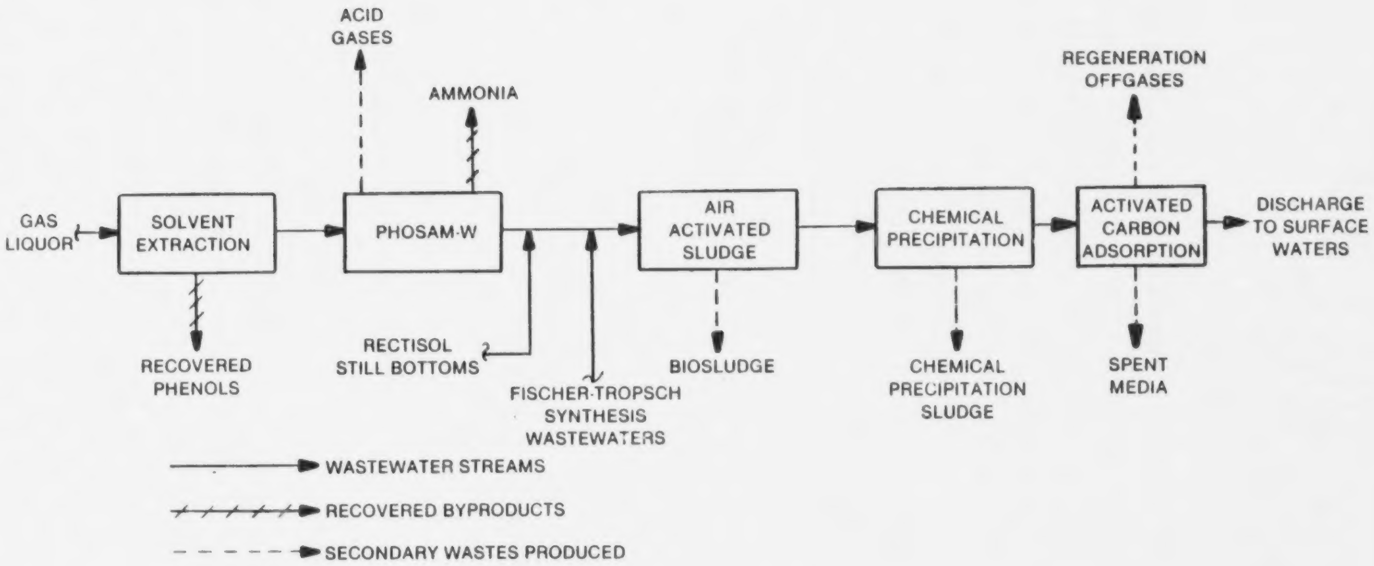

Figure 4-11. Block flow diagram for integrated control example No. 1

Phosam-W process for dissolved gases removal. The resulting extracted and stripped gas liquor is then combined with Rectisol still bottoms and Fischer-Tropsch synthesis wastewater for dissolved organics removal in an air-activated sludge unit. Effluent from the activated sludge unit is then treated for dissolved inorganics by chemical precipitation and for residual organics by activated carbon adsorption. The treated effluent is discharged to surface waters. At the present time, there is no publicly available information indicating that a proposed Lurgi-based synfuel plant will use this approach nor what the treatment scheme would be if this approach were selected. This example therefore was constructed based on engineering analysis (for a generalized situation) and should not be construed to necessarily represent an acceptable treatment scheme for a given facility.

Illinois No. 6 coal is the basis for this surface discharge example. This feedstock is found in regions where adequate supplies of makeup water are generally available. Therefore, plants which are likely to use an Illinois No. 6-type feedstock would be more likely to consider discharge of treated wastewaters (i.e., they would not necessarily be faced with the need to reuse wastewaters in order to minimize raw water makeup requirements) than facilities located in arid regions (and assumed to use western coal feedstocks).

The estimated material flows and compositions for this example are shown in Table 4-58. This control example provides for significant reductions in most pollutant species. Also, the chemical precipitation process is expected to reduce the trace metals content of the effluent, although no information on trace elements is shown in this presentation.

This integrated control example produces the following secondary waste streams and byproducts:

TABLE 4-58. ESTIMATED MATERIAL FLOWS AND COMPOSITIONS - INTEGRATED CONTROL EXAMPLE NO. 1

	Gas Liquor	Extracted Gas Liquor	Stripped Gas Liquor	Rectisol Still Bottoms	Fischer-Tropsch Wastewater	Combined Wastewaters	Biox Effluent	Chemical Precipitation Effluent	Activated Carbon Absorption Effluent[a]
Wastewater Flow Rate,[b] (m^3/hr)	498	498	497	12	71	580	579	578	578
Constituent Compositions,[b] (mg/L)									
COD	8,900	3,700	3,700	120	12,900	4,800	960	190	190
BOD	4,570	860	860	85	9,000	1,800	190	72	72
TOC	2,980	1,300	1,300	31	4,800	1,700	340	100	100
Phenol	2,280	150	150			130	6	0.006	0.006
Organic Acids	380	320	320	81	12,100	1,800	88	26	26
Tars and Oils	500	50	50			43	13	0.1	0.1
CN^- (as HCN)	37	37	19	16		16	5	2	2
SCN^-	160	160	160			140	41	21	21
NH_4^+ (as NH_3)	4,800	4,800	150	65		130	40	40	40
Cl^-	95	95	95	605		94	94	94	94
$CO_3^=$ (as CO_2)	7,780	7,780	1			1	c	c	c
$S^=$ (as H_2S)	290	290	1			1	1	1	1
TDS	1,860	c	c			c	c	c	c

[a] Effluent to Surface Waters.

[b] Flow rates and compositions are calculated values for the Illinois coal/F-T synthesis case.

[c] The fate of carbonate and TDS in this integrated control example has not been determined.

Blanks indicate not applicable or no data available.

Secondary Waste Streams		Byproducts	
Acid gases	(120 kg mole/hr)	Phenols	(1090 kg/hr)
Biosludge	(1930 kg/hr)	Ammonia	(2320 kg/hr)
Regeneration off-gases	(145 kg mole/hr average)		
Chemical precipitation sludge	(1000 kg/hr)		
Spent carbon adsorption media	(small and intermittent flow rate)		

The carbon adsorption regeneration offgases will contain a small amount of carbon monoxide and any sulfur species that are in the regenerator fuel. NO_x emissions in this stream are not expected to be significant.

Table 4-59 summarizes the estimated capital and total annualized costs for this integrated control example. For the total system, capital requirements are estimated to be $51.5 million or 5.3 percent of the base plant costs. Total annualized costs are estimated to be $13.2 million per year or 4.9 percent of base plant costs.

TABLE 4-59. ESTIMATED COSTS - CONTROL EXAMPLE NO. 1[a]

Pollution Control Process	Capital Requirement, 10^6\$	Total Annualized Cost, 10^6 \$/yr
Solvent Extraction	14.4	4.8
PHOSAM-W	14.4	2.9
Biological Oxidation	14.8	3.1
Chemical Precipitation	2.5	0.8
Activated Carbon Adsorption	5.3	1.7
TOTAL SYSTEM	51.5	13.2

[a] Costs are first quarter 1980 dollars.

Integrated Control Example No. 2

Deepwell injection has been used to dispose of many industrial wastes in several areas of the country. This disposal method has also been discussed (although not proposed for disposal of waste brines) as a potential approach for treated synfuels aqueous wastes. For these reasons, two control examples are given in this manual to illustrate the possible integration of deepwell injection technology with potential pretreatment steps. Example No. 2 differs from Example No. 3 only in that Example No. 2 uses forced evaporation to achieve volume reduction while Example No. 3 uses cooling tower concentration. Both of these examples are based on the Rosebud coal/F-T synthesis case.

In integrated control example No. 2 (Figure 4-12) extracted and stripped gas liquor is combined with Rectisol still bottoms and F-T synthesis wastewater and sent to an air-activated sludge unit. The activated sludge unit effluent wastewater stream is concentrated by forced evaporation (to reduce the overall costs of the treatment system), incinerated to remove residual organics that could cause operating problems (e.g., plugging of the formation) for the injection well system, and then deepwell injected. The estimated material flows and compositions for this example are shown in Table 4-60.

This control example produces the following secondary waste streams and byproducts:

Secondary Waste Streams		Byproducts	
Acid gases	(120 kg mole/hr)	Phenols	(1300 kg/hr)
Biosludge	(2700 kg/hr)	Ammonia	(2200 kg/hr)
Incinerator quench offgas	(5200 kg mole/hr)	Water	(346,000 kg/hr)

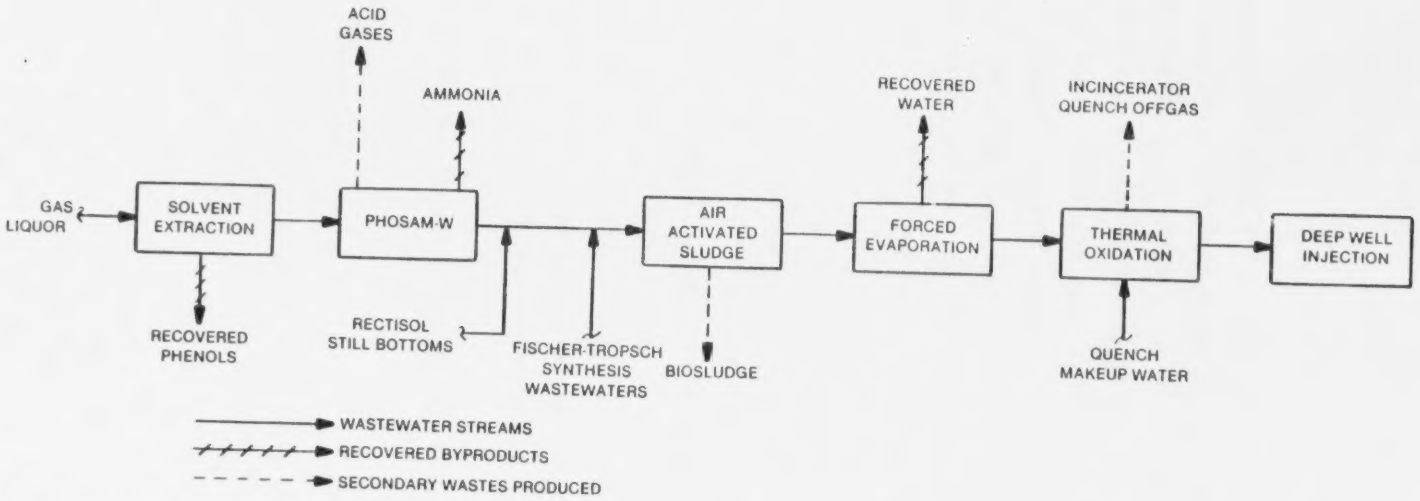

Figure 4-12. Block flow diagram for integrated control example No. 2

TABLE 4-60. ESTIMATED MATERIAL FLOWS AND COMPOSITIONS - INTEGRATED CONTROL EXAMPLE NO. 2

	Gas Liquor	Extracted Gas Liquor	Stripped Gas Liquor	Rectisol Still Bottoms	Fischer-Tropsch Wastewater	Combined Wastewaters	Biox Effluent	Forced Evaporator Brine	Incinerator Brine to Disposal
Wastewater Flow Rate,[a] (m^3/hr)	293	293	292	10	76	378	377	30	30
Constituent Compositions:[a] (mg/L)									
COD	22,800	12,300	12,300	140	11,500	11,800	2,400	29,600	30
BOD	10,600	3,100	3,100	98	8,000	4,000	400	5,000	5
TOC	7,600	4,200	4,200	36	4,300	4,100	830	10,300	10
Phenol	4,500	290	290			230	11	140	0.1
Organic Acids	2,000	1,700	1,700	94	10,700	3,500	170	2,200	2
Tars and Oils	150	50	50			39	12	150	0.1
CN^- (as HCN)	5	5	3	19		2	0.7	9	0.009
SCN^-	6	6	6			5	1	17	0.02
NH_4^+ (as NH_3)	7,600	7,600	150	74		120	5	62	0.06
Cl^-	25	25	25	700		38	38	470	470
$CO_3^=$ (as CO_2)	13,600	13,600	1			1	b	b	b
$S^=$ (as H_2S)	55	55	1			1	1	10	0.01
TDS	2,500	b	b			b	b	b	b

[a] Flow rates and compositions are calculated values for the Illinois coal/F-T synthesis case.

[b] The fate of carbonate and TDS in this integrated control example has not been determined.

Blanks indicate not applicable or no data available.

The incinerator quench offgas flow is based on burning Lurgi oil (0.5 percent sulfur) with 15% excess air. For this case, this stream will contain approximately 9% CO_2, 39% H_2O, 200 ppmv SO_2, 90 ppmv NO_x, 35 ppmv CO, 10 ppmv hydrocarbons, and 4 g/Nm^3 particulate matter. An incinerator quench makeup water flow rate of 30 m^3/hr is required.

Table 4-61 summarizes the estimated capital and total annualized costs for this integrated control example. For the total system, capital requirements are estimated to be $65.7 million or 6.7 percent of the base plant costs. Total annualized costs are estimated to be 21.4 million per year or 9.1 percent of base plant costs.

TABLE 4-61. ESTIMATED COSTS - CONTROL EXAMPLE NO. 2[a]

Pollution Control Process	Capital Requirement, 10^6\$	Total Annualized Cost, 10^6\$/yr
Solvent Extraction	10.6	2.7
PHOSAM-W	11.8	1.5
Biological Oxidation	16.3	3.5
Forced Evaporation	19.6	5.9
Incineration	5.5	7.3
Deepwell Injection	1.9	0.4
TOTAL SYSTEM	65.7	21.4

[a] Costs are first quarter 1980 dollars.

Integrated Control Example No. 3

This integrated control example (Figure 4-13) is similar to Example No. 2 except that a cooling tower is used for concentration rather than forced evaporation. The estimated material flows and compositions for this example are shown in Table 4-62. This control example produces the following secondary waste streams and byproducts:

Secondary Waste Streams		Byproducts	
Acid gases	(120 kg mole/hr)	Phenols	(1300 kg/hr)
Biosludge	(2700 kg/hr)	Ammonia	(2200 kg/hr)
Cooling tower evaporation	(375,000 kg/hr)		
Cooling tower drift	(1900 kg/hr)		
Incinerator quench offgas	(7400 kg mole/hr)		

The incinerator quench offgas flow is for burning Lurgi oil (0.5 percent sulfur) with 15% excess air. The incinerator quench offgas composition is the same for this example as was given in example No. 2. For this example, additional raw water makeup to the cooling tower of 40 m^3/hr is required. Also, an incinerator quench makeup water flow rate of 40 m^3/hr is required.

Table 4-63 summarizes the estimated capital and total annualized costs for this integrated control example. For the total system, capital requirements are estimated to be $46.8 million or 4.8 percent of base plant costs. Total annualized costs are estimated to be $17.6 million per year or 7.5 percent of base plant costs.

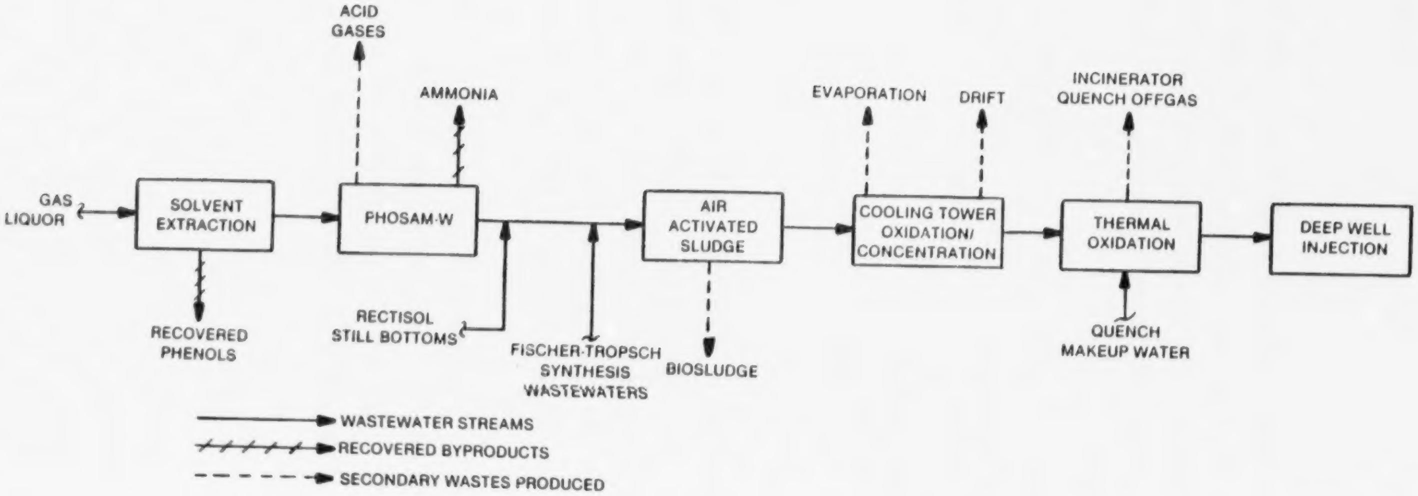

Figure 4-13. Block flow diagram for integrated control example No. 3

TABLE 4-62. ESTIMATED MATERIAL FLOWS AND COMPOSITIONS - INTEGRATED CONTROL EXAMPLE NO. 3

	Gas Liquor	Extracted Gas Liquor	Stripped Gas Liquor	Rectisol Still Bottoms	Fischer-Tropsch Wastewater	Combined Wastewaters	Biox Effluent	Cooling Tower Blowdown	Incinerated C.T. Blowdown to Disposal
Wastewater Flow Rate,[a] (m^3/hr)	293	293	292	10	76	378	377	40	40
Constituent Compositions,[a] (mg/L)									
COD	22,800	12,300	12,300	140	11,500	11,800	2,400	21,400	21
BOD	10,600	3,100	3,100	98	8,000	4,000	400	3,600	4
TOC	7,600	4,200	4,200	36	4,300	4,100	830	7,500	7
Phenol	4,500	290	290			230	11	100	0.1
Organic Acids	2,000	1,700	1,700	94	10,700	3,500	170	1,600	2
Tars and Oils	150	50	50			39	12	110	0.1
CN^- (as HCN)	5	5	3	19		2	0.7	7	0.007
SCN^-	6	6	6			5	1	13	0.01
NH_4^+ (as NH_3)	7,600	7,600	150	74		120	5	16	0.02
Cl^-	25	25	25	700		38	38	340	340
$CO_3^=$ (as CO_2)	13,600	13,600	1			1	b	b	b
$S^=$ (as H_2S)	55	55	1			1	1	7	0.007
TDS	2,500	b	b			b	b	b	b

[a] Flow rates and compositions are calculated values for the Illinois coal/F-T synthesis case.
[b] The fate of carbonate and TDS in this integrated control example has not been determined.
Blanks indicate not applicable or no data available.

TABLE 4-63. ESTIMATED COSTS - CONTROL EXAMPLE NO. 3[a]

Pollution Control Process	Capital Requirement, 10^6\$	Total Annualized Cost, 10^6\$/yr
Solvent Extraction	10.6	2.7
PHOSAM-W	11.8	1.5
Biological Oxidation	16.3	3.5
Cooling Tower Concentration	–	–
Incineration	6.2	9.4
Deep Well Injection	1.9	0.4
TOTAL SYSTEM	46.8	17.6

[a] Costs are first quarter 1980 dollars.

Integrated Control Example No. 4

The configuration of this control example (No. 4) has some features which are similar to the proposed wastewater management strategy for the Hampshire Energy project (Mobil M-gasoline synthesis plant) and includes volume reduction (for economic and water conservation purposes) and residual disposal in a surface impoundment. In this integrated control example (Figure 4-14) extracted and stripped gas liquor is combined with Rectisol still bottoms and F-T synthesis wastewater and sent to an air-activated sludge unit. The activated sludge effluent is then concentrated in a cooling tower and the cooling tower blowdown stream sent to a surface impoundment.

The estimated material flows and compositions for this example (based on Rosebud coal) are shown in Table 4-64. The impounded stream is not completely removed from the environment since evaporative losses and a potential leachate stream will exist. This control example produces the following secondary waste streams and byproducts:

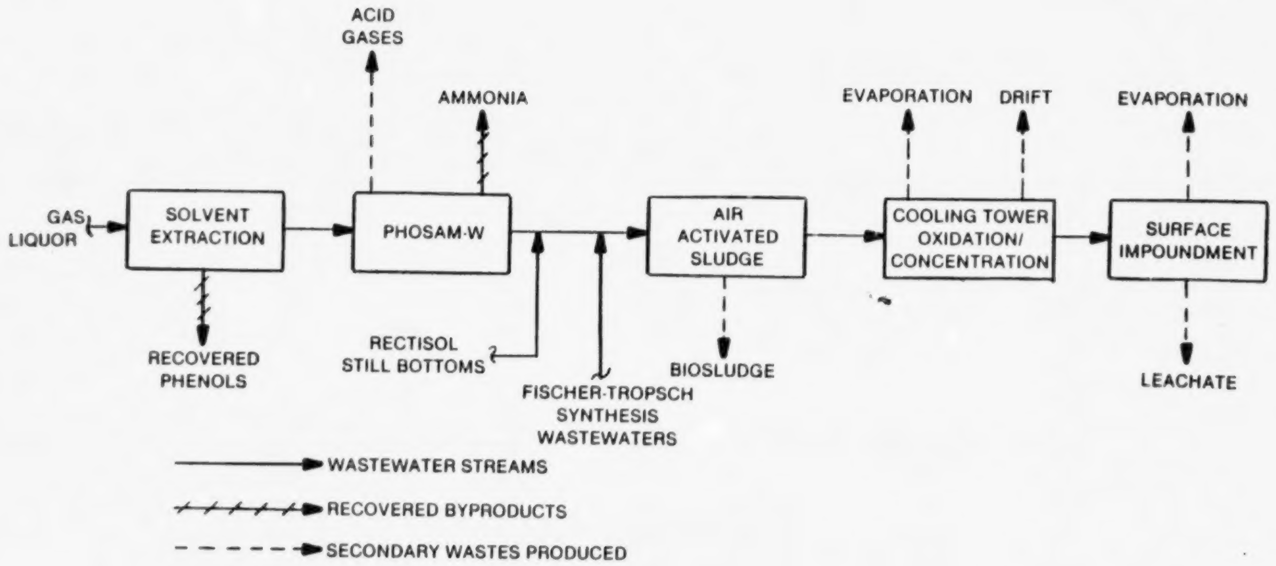

Figure 4-14. Block flow diagram for integrated control example No. 4

TABLE 4-64. ESTIMATED MATERIAL FLOWS AND COMPOSITIONS - INTEGRATED CONTROL EXAMPLE NO. 4

	Gas Liquor	Extracted Gas Liquor	Stripped Gas Liquor	Rectisol Still Bottoms	Fischer-Tropsch Wastewater	Combined Wastewaters	Bioz Effluent	Cooling Tower Blowdown to Surface Impoundment
Wastewater Flow Rate,[a] (m^3/hr)	293	293	292	10	76	378	377	40
Constituent Compositions,[a] (mg/L)								
COD	22,800	12,300	12,300	140	11,500	11,800	2,400	21,400
BOD	10,600	3,100	3,100	98	8,000	4,000	400	3,600
TOC	7,600	4,200	4,200	36	4,300	4,100	830	7,500
Phenol	4,500	290	290			230	11	100
Organic Acids	2,000	1,700	1,700	94	10,700	3,500	170	1,600
Tars and Oils	150	50	50			39	12	110
CN^- (as HCN)	5	5	3	19		2	0.7	7
SCN^-	6	6	6			5	1	13
NH_4^+ (as NH_3)	7,600	7,600	150	74		120	5	16
Cl^-	25	25	25	700		38	38	340
$CO_3^=$ (as CO_2)	13,600	13,600	1			1	b	b
$S^=$ (as H_2S)	55	55	1			1	1	7
TDS	2,500	b	b			b	b	b

[a] Flow rates and compositions are calculated values for the Illinois coal/F-T synthesis case.

[b] The fate of carbonate and TDS in this integrated control example has not been determined.

Blanks indicate not applicable or no data available.

Secondary Waste Streams	
Acid Gases	(120 kg mole/hr)
Biosludge	(2700 kg/hr)
Cooling tower evaporation	(375,000 kg/hr)
Cooling tower drift	(1900 kg/hr)
Impoundment evaporation	(~40,000 kg/hr)
Impoundment leachate	(unknown flow rate)

Byproducts	
Phenols	(1300 kg/hr)
Ammonia	(2200 kg/hr)

For this example, additional raw water makeup to the cooling tower of 40 m^3/hr is required.

Table 4-65 summarizes the estimated capital and total annualized costs for this integrated control example. For the total system, capital requirements are estimated to be $43.8 million or 4.5 percent of base plant costs. Total annualized costs are estimated to be $8.8 million per year or 3.8 percent of base plant costs.

TABLE 4-65. ESTIMATED COSTS - CONTROL EXAMPLE NO. 4[a]

Pollution Control Process	Capital Requirement, 10^6\$	Total Annualized Cost, 10^6\$/yr
Solvent Extraction	10.6	2.7
PHOSAM-W	11.8	1.5
Biological Oxidation	16.3	3.5
Cooling Tower Concentration	--	--
Surface Impoundment	5.1	1.1
TOTAL SYSTEM	43.8	8.8

[a] Costs are first quarter 1980 dollars.

Integrated Control Example No. 5

The configuration of this control example (Figure 4-15) is similar to Example No. 4 except that volume reduction is achieved by forced evaporation rather than cooling tower concentration. The estimated material flows and compositions for this example are shown in Table 4-66. This control example produces the following secondary waste streams and byproducts:

Secondary Waste Streams		Byproducts	
Acid gas	(120 kg-mole/hr)	Phenols	(1300 kg/hr)
Biosludge	(2700 kg/hr)	Ammonia	(2200 kg/hr)
Impoundment evaporation	(~30,000 kg/hr)	Water	(348,000 kg/hr)
Impoundment leachate	(unknown flow rate)		

Table 4-67 summarizes the estimated capital and total annualized costs for this integrated control example. For the total system, capital requirements are estimated to be $62.2 million or 6.4 percent of base plant costs. Total annualized costs are estimated to be $14.5 million per year or 6.2 percent of base plant costs.

Integrated Control Example No. 6

The configuration of this control example (No. 6) has some features which are similar to the proposed wastewater management system for the Nokota project (Methanol synthesis plant) and includes codisposal of the residual wastewater stream with ash. Both cooling tower concentration and forced evaporation are used for volume reduction. In this integrated control example (Figure 4-16), extracted and stripped gas liquor is combined with Rectisol still bottoms and F-T synthesis wastewater and sent to an air-activated sludge unit. The activated sludge unit effluent is concentrated by cooling tower oxidation/concentration and then further concentrated by forced evaporation. The

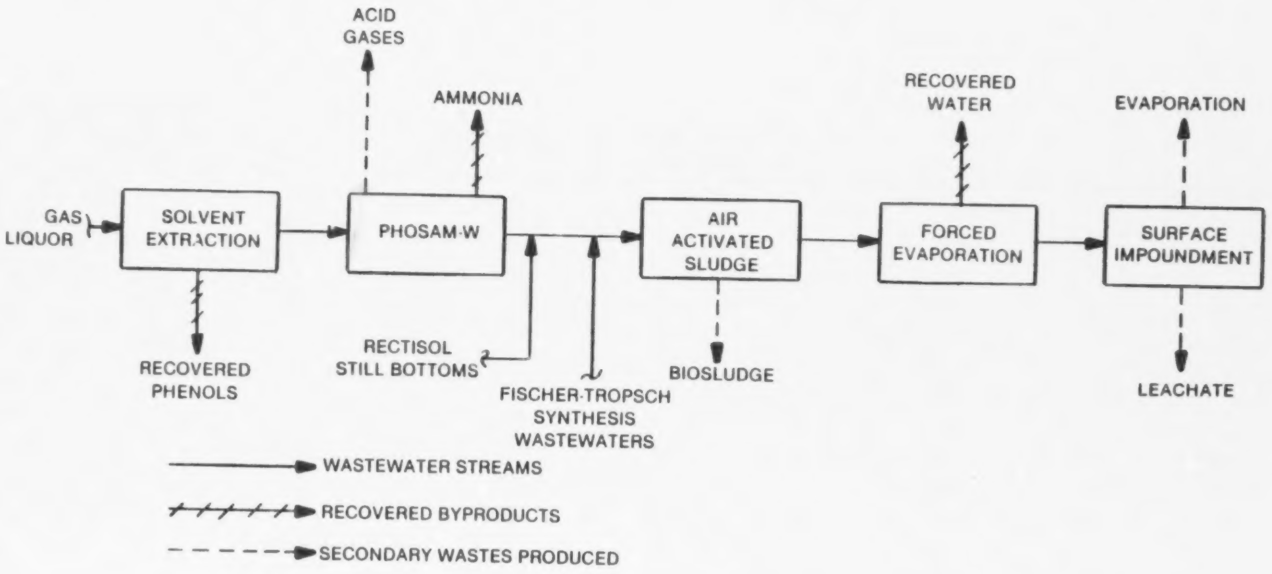

Figure 4-15. Block flow diagram for integrated control example No. 5

TABLE 4-66. ESTIMATED MATERIAL FLOWS AND COMPOSITIONS - INTEGRATED CONTROL EXAMPLE NO. 5

	Gas Liquor	Extracted Gas Liquor	Stripped Gas Liquor	Rectisol Still Bottoms	Fischer-Tropsch Wastewater	Combined Wastewaters	Biox Effluent	Forced Evaporator Brine to Surface Impoundment
Wastewater Flow Rate,[a] (m^3/hr)	293	293	292	10	76	378	377	30
Constituent Compositions,[a] (mg/L)								
COD	22,800	12,300	12,300	140	11,500	11,800	2,400	29,600
BOD	10,600	3,100	3,100	98	8,000	4,000	400	5,000
TOC	7,600	4,200	4,200	36	4,300	4,100	830	10,300
Phenol	4,500	290	290			230	11	140
Organic Acids	2,000	1,700	1,700	94	10,700	3,500	170	2,200
Tars and Oils	150	50	50			39	12	150
CN^- (as HCN)	5	5	3	19		2	0.7	9
SCN^-	6	6	6			5	1	17
NH_4^+ (as NH_3)	7,600	7,600	150	74		120	5	62
Cl^-	25	25	25	700		38	38	470
$CO_3^=$ (as CO_2)	13,600	13,600	1			1	b	b
$S^=$ (as H_2S)	55	55	1			1	1	10
TDS	2,500	b	b			b	b	b

[a] Flow rates and compositions are calculated values for the Illinois coal/F-T synthesis case.
[b] The fate of carbonate and TDS in this integrated control example has not been determined.
Blanks indicate not applicable or no data available.

TABLE 4-67. ESTIMATED COSTS - CONTROL EXAMPLE NO. 5[a]

Pollution Control Process	Capital Requirement, 10^6\$	Total Annualized Cost, 10^6\$/yr
Solvent Extraction	10.6	2.7
PHOSAM-W	11.8	1.5
Biological Oxidation	16.3	3.5
Forced Evaporation	19.6	5.9
Surface Impoundment	3.9	0.8
TOTAL SYSTEM	62.2	14.5

[a] Costs are first quarter 1980 dollars.

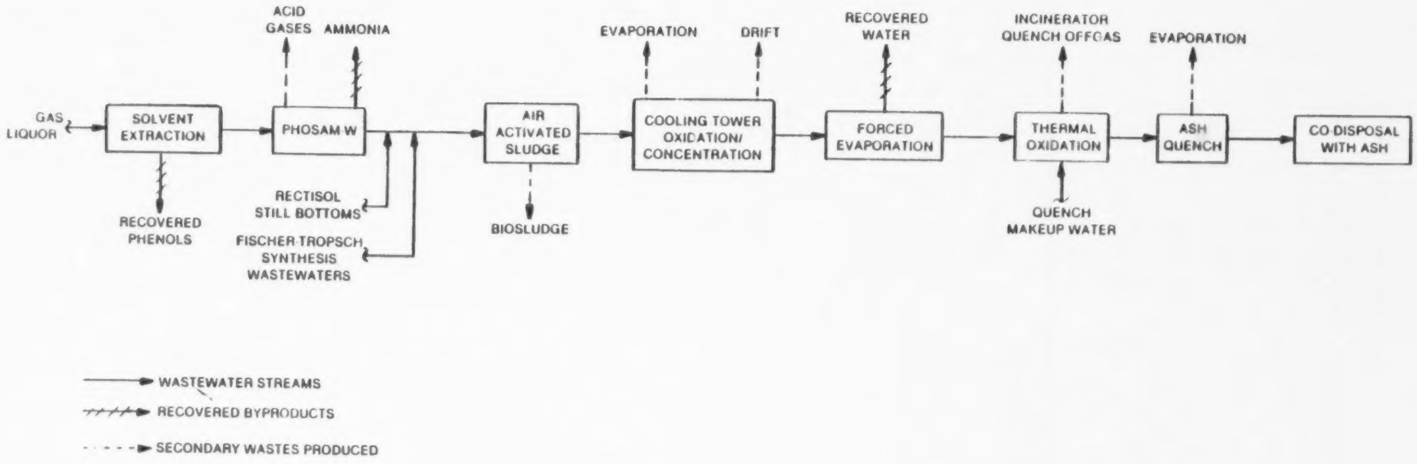

Figure 4-16. Block flow diagram for integrated control example No. 6

resultant treated and concentrated wastewater is then incinerated and used as gasifier/ boiler ash quench water. The residual wastewater (that which is not evaporated in the ash quenching operation) is disposed of along with the ash. In this example, the wastewater stream is incinerated to avoid contaminating the ash with organics and possibly causing the ash to become a hazardous waste requiring special disposal procedures with higher disposal costs.

The estimated material flows and compositions for this example (based on Rosebud coal) are shown in Table 4-68. This control example produces the following secondary waste streams and byproducts:

Secondary Waste Streams	
Acid gases	(120 kg mole/hr)
Biosludge	(2700 kg/hr)
Cooling tower evaporation	(375,000 kg/hr)
Cooling tower drift	(1900 kg/hr)
Incinerator quench offgas	(3400 kg mole/hr)
Ash quench evaporation	(5800 kg/hr)

Byproducts	
Phenols	(1300 kg/hr)
Ammonia	(2200 kg/hr)
Water	(20,000 kg/hr)

The incinerator quench offgas flow is for burning Lurgi oil (0.5 percent sulfur) with 15% excess air. The incinerator quench offgas composition for this example is the same as was given for Example No. 2. For this example, additional raw water makeup to the cooling tower of 40 m^3/hr is required. Also, an incinerator quench makeup flow rate of 20 m^3/hr is required.

Table 4-69 summarizes the estimated capital and total annualized costs for this integrated control example. For the total system, capital requirements are estimated to be $45.5 million or 4.6 percent of base plant costs. Total annualized costs are estimated to be $13.4 million per year or 5.7 percent of base plant costs.

TABLE 4-68. ESTIMATED MATERIAL FLOWS AND COMPOSITIONS - INTEGRATED CONTROL EXAMPLE NO. 6

	Gas Liquor	Extracted Gas Liquor	Stripped Gas Liquor	Rectisol Still Bottoms	Fischer-Tropsch Wastewater	Combined Wastewaters	Biox Effluent	Cooling Tower Blowdown	Forced Evaporator Brine	Incinerated Brine to Ash Quenching	Residual Disposed with Quenched Ash
Wastewater Flow Rate,[a] (m^3/hr)	293	293	292	10	76	378	377	40	20		
Constituent Compositions,[a] (mg/L)											
COD	22,800	12,300	12,300	140	11,500	11,800	2,400	21,400	43,000	43	61
BOD	10,600	3,100	3,100	98	8,000	4,000	400	3,600	7,300	7	10
TOC	7,600	4,200	4,200	36	4,300	4,100	830	7,500	15,000	15	21
Phenol	4,500	290	290			230	11	100	210	0.2	0.3
Organic Acids	2,000	1,700	1,700	94	10,700	3,500	170	1,600	32,000	3	4
Tars and Oils	150	50	50			39	12	110	210	0.2	0.3
CN^- (as HCN)	5	5	3	19		2	0.7	7	13	0.01	0.02
SCN^-	6	6	6			5	1	13	25	0.03	0.04
NH_4^+ (as NH_3)	7,600	7,600	150	74		120	5	16	32	0.03	0.04
Cl^-	25	25	25	700		38	38	340	690	690	970
$CO_3^=$ (as CO_2)	13,600	13,600	1			1	b	b	b	b	a
$S^=$ (as H_2S)	55	55	1			1	1	7	14	0.01	0.02
TDS	2,500	b	b			b	b	b	b	b	b

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[a] Flow rates and compositions are calculated values for the Illinois coal/F-T synthesis case.

[b] The fate of carbonate and TDS in this integrated control example has not been determined.

Blanks indicate not applicable or no data available.

TABLE 4-69. ESTIMATED COSTS - CONTROL EXAMPLE NO. 6[a]

Pollution Control Process	Capital Requirement, 10^6\$	Total Annualized Cost, 10^6\$/yr
Solvent Extraction	10.6	2.7
PHOSAM-W	11.8	1.5
Biological Oxidation	16.3	3.5
Cooling Tower Concentration	-	-
Forced Evaporation	2.2	0.6
Incineration	4.6	5.0
Co-disposal With Ash	-	-
TOTAL SYSTEM	45.5	13.4

[a] Costs are first quarter 1980 dollars.

Integrated Control Example No. 7

The configuration of integrated control example No. 7 has some features which are similar to the proposed wastewater management strategy for the Great Plains Coal Gasification Associates, Inc. SNG project. This control example (Figure 4-17) is the same as Example No. 6 except that there is no activated sludge unit and only gas liquor and Rectisol still bottoms are treated. These two wastewaters would exist if the plant produced substitute natural gas. Omitting the activated sludge unit results in greater organics concentrations in the cooling tower makeup water. Thus, in this example it is more likely that COD, BOD, TOC, etc. reductions will occur in the cooling tower than in previous examples (Nos. 3, 4, and 6) where less organic material is charged to the cooling tower. These cooling tower oxidation effects have not, however, been demonstrated and are not shown in this example. Also, due to the higher organics (and other species) loadings in the cooling tower, the cooling tower evaporation and drift streams are more likely to contain significant amounts of pollutants.

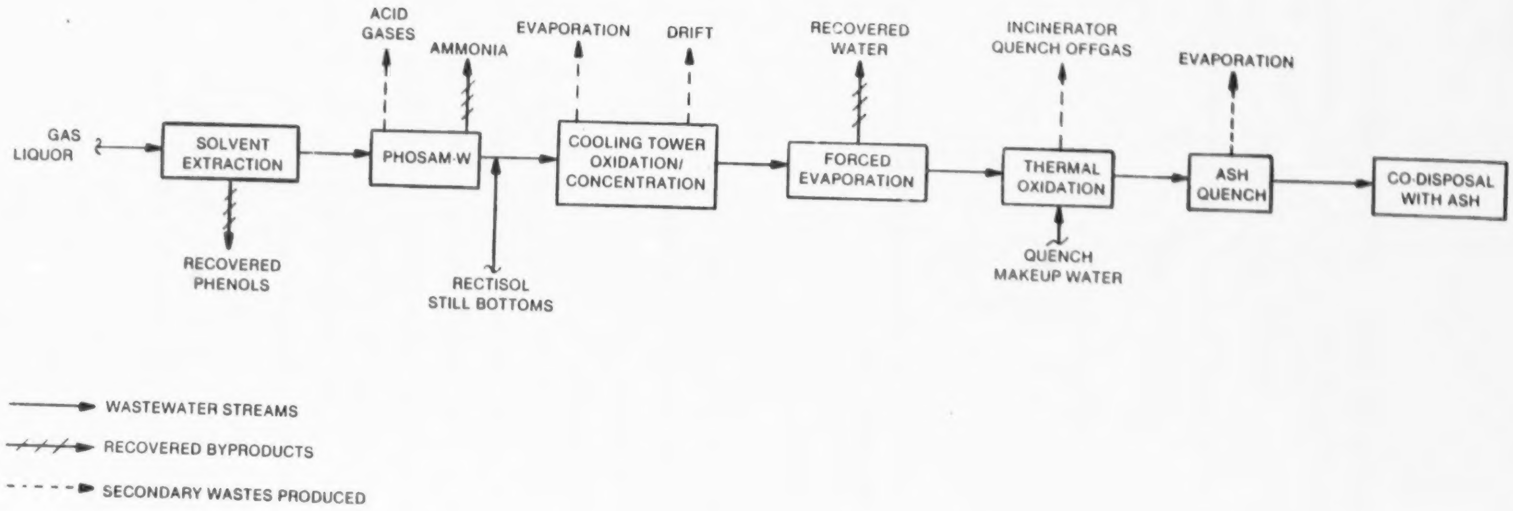

Figure 4-17. Block flow diagram for integrated control example No. 7

The estimated material flows and compositions for this example (Rosebud coal case) are shown in Table 4-70. This control example produces the following secondary waste streams and byproducts:

Secondary Waste Streams	
Acid gases	(120 kg mole/hr)
Cooling tower evaporation	(375,000 kg/hr)
Cooling tower drift	(1900 kg/hr)
Incinerator quench offgas	(3400 kg mole/hr)
Ash quench evaporation	(5800 kg/hr)

Byproducts	
Phenols	(1300 kg/hr)
Ammonia	(2200 kg/hr)
Water	(20,000 kg/hr)

The incinerator quench offgas flow is for burning Lurgi oil (0.5 percent sulfur) with 15% excess air. The incinerator quench offgas composition for this example is the same as was given for Example No. 2. For this example, additional raw water makeup to the cooling tower of 114 m^3/hr is required. Also, an incinerator quench makeup flow rate of 20 m^3/hr is required.

Table 4-71 summarizes the estimated capital and total annualized costs for this integrated control example. For the total system, capital requirements are estimated to be $29.2 million or 3.6 percent of base plant costs. Total annualized costs are estimated to be $9.9 million per year or 4.9 percent of base plant costs.

TABLE 4-70. ESTIMATED MATERIAL FLOWS AND COMPOSITIONS - INTEGRATED CONTROL EXAMPLE NO. 7

	Gas Liquor	Extracted Gas Liquor	Stripped Gas Liquor	Rectisol Still Bottoms	Combined Wastewaters	Cooling Tower Blowdown	Forced Evaporator Brine	Incinerated Brine to Ash Quenching	Residual Disposed with Quenched Ash
Wastewater Flow Rate,[a] (m^3/hr)	293	293	292	10	302	40	20	20	14
Constituent Compositions,[a] (mg/L)									
COD	22,800	12,300	12,300	140	12,000	87,000	170,000	170	250
BOD	10,600	3,100	3,100	98	3,000	22,000	44,000	44	62
TOC	7,600	4,200	4,200	36	4,100	30,000	60,000	60	85
Phenol	4,500	290	290		280	2,000	4,000	4	6
Organic Acids	2,000	1,700	1,700	94	1,600	12,000	24,000	24	34
Tars and Oils	150	50	50		48	350	700	0.7	1
CN^- (as HCN)	5	5	3	19	3	22	44	0.04	0.06
SCN^-	6	6	6		6	42	84	0.08	0.1
NH_4^+ (as NH_3)	7,600	7,600	150	74	150	370	740	0.7	1
Cl^-	25	25	25	700	47	340	680	680	980
$CO_3^=$ (as CO_3)	13,600	13,600	1		b	b	b	b	b
$S^=$ (as H_2S)	55	55	1		1	7	14	0.01	0.02
TDS	2,500	b	b		b	b	b	b	b

[a] Flow rates and compositions are calculated values for the Illinois coal/F-T synthesis case.

[b] The fate of carbonate and TDS in this integrated control example has not been determined.

Blanks indicate not applicable or no data available.

TABLE 4-71. ESTIMATED COSTS - CONTROL EXAMPLE NO. 7[a]

Pollution Control Process	Capital Requirement, 10^6\$	Total Annualized Cost, 10^6\$/yr
Solvent Extraction	10.6	2.7
PHOSAM-W	11.8	1.5
Cooling Tower Concentration	–	–
Forced Evaporation	2.2	0.6
Incineration	4.6	5.0
Codisposal With Ash	–	–
TOTAL SYSTEM	29.2	9.9

[a] Costs are first quarter 1980 dollars.

4.2.3 Control Applications for Specific Streams Containing Primarily Inorganic Compounds

The waste streams in this source type are not unique to Lurgi-based synfuels plants. As was discussed earlier, controls for these non-unique streams in a Lurgi plant would be similar to the controls which would be used for similar streams in existing U.S. industries. For example, the blowdown stream from a coal-fired boiler in a Lurgi-based synfuels plant would have characteristics and treatment needs which are essentially the same as for blowdown from a coal-fired boiler in other industries.

These streams and their controls will not be discussed in depth in this manual since this PCTM concentrates on the control of streams which are unique to Lurgi-based synfuels plants. Therefore, this section discusses the available control options but does not present influent and effluent wastewater compositions and flows or treatment costs.

Gasifier Ash and Boiler Ash Quench/Sluice Blowdown

The wastewaters resulting from gasifier and boiler ash quenching are expected to be similar in composition as long as similar quality waters are used. These waters will primarily contain suspended solids and inorganics leached from the ash. The pH may be high or low depending on the leachable components in the ash. The primary objectives in treating this waste stream are removal of suspended solids and neutralization.

One approach to the treatment/reuse of this stream involves closed loop operation of the sluicing system. Under this mode of operation, the quench/sluice waters are routed to a clarifier or settling pond which separates the ash while the overflow water is recirculated. A Lurgi-based system should be able to operate in this mode because the water associated with the quenched gas (80 wt% solids) should remove sufficient quantities of dissolved solids to satisfy dissolved species blowdown requirements. Another approach involves pH adjustment and removal of suspended solids. The clarified stream could be considered for discharge to some surface waters if the trace element concentrations are not significant.

Methanation and CO_2 Removal Condensates

The condensates which result from methanation and CO_2 removal from crude SNG will be of high quality. The primary contaminants will be small quantities of dissolved gases (e.g., CO_2, CH_4). The objective in treating this stream will be to remove dissolved gases (as necessary) prior to reuse.

These condensates may be used directly as cooling tower or raw water makeup. Alternately, they can be routed to the boiler feedwater deaerator or demineralizer decarbonator for dissolved gas removal prior to use as boiler feedwater. Use of these condensates as makeup to the boiler feedwater system will reduce feedwater treatment costs because of the low concentrations of dissolved inorganic solids in these streams. Their use will also decrease the volume of demineralizer regeneration wastewaters. Since boiler feedwater makeup treatment equipment is designed to satisfy total plant makeup needs based upon raw water, the use of these condensates in this system will not affect the capital investment but will reduce operating costs.

Raw Coal Storage Runoff

The runoff associated with raw coal storage/handling will be an intermittent stream with a highly variable composition. It will contain suspended and dissolved solids as well as inorganic compounds leached from the coal.

The objectives in treating this stream include removal of suspended and dissolved solids. An approach which might allow discharge involves routing the wastewater to a sedimentation pond where the suspended solids are allowed to settle out. Lime or acid can be added for pH adjustment where required. Chemical precipitation may occur as a result of pH adjustment, thus potentially removing some additional undesirable dissolved solids. The effluent may then be discharged to surface waters, recycled, or sent to final disposal. Reuse of the runoff as cooling tower makeup is an alternative to discharge. The treatment utilized for this approach is expected to be similar to that for discharge.

Demineralizer Regeneration Wastewaters

The wastewaters which result from demineralizer regeneration are generated at relatively high flow rates. These wastewaters contain high concentrations of dissolved inorganic salts. One approach to treatment of this wastewater involves removal of suspended solids and chemical precipitation. These steps may produce a water quality which could be discharged at some plant sites. If a discharge approach is not available, then wastewater concentrating steps would probably be needed to reduce the cost of residual disposal. A substantial portion of the volume reduction may be accomplished by segregating high quality demineralizer regeneration wastewaters from low quality wastewaters. Portions of the initial raw water backwash and much of the final rinse water will be of raw water quality or better and can be reused without treatment.

If chemical precipitation is used, a sludge containing approximately 20 weight percent solids will be produced. Treatment alternatives for this secondary waste stream are discussed in Section 4.3.

Boiler Blowdown

The blowdown from the auxiliary boilers has a quality comparable in dissolved solids to the raw water makeup supply. It has a relatively low flow rate when compared to the other streams presented in this section. The blowdown will contain low to moderate amounts of inorganic dissolved solids including treatment chemicals and traces of dissolved metals.

The objectives in treating this stream depend on the reuse/disposal route to be taken. If the blowdown is to be reused as boiler feedwater, removal of dissolved solids and residual treatment chemicals will be needed. In this instance, it could be routed to the boiler feedwater treatment system upstream of the sedimentation/equalization basin. If the blowdown may be discharged, pH adjustment and sedimentation may be desirable.

Cooling Tower Blowdown

The cooling tower blowdown is a large stream which contains fairly high concentrations of dissolved solids. The expected flows and compositions of the various cooling tower blowdown streams for raw water makeup cases were given in Section 3. The flow rate and composition of the blowdown will be a function of the heat load on the tower and the cycles of concentration at which the system is operated. For a given plant heat load, the cycles of concentration will be determined by the quality of the makeup water fed to the tower. The compositions listed in Section 3 are for operation at 5 cycles of concentration.

As discussed in previous sections, some control alternatives for treatment of raw gas liquor and related wastewaters employ the cooling tower as a means of concentrating the wastewater. This discussion deals only with treatment of the cooling tower blowdown when raw water is the only source of cooling tower makeup.

The objectives in treating the blowdown depend on the disposal/reuse options available. If operation with no discharge is desired, the objective would be to minimize the blowdown flow. If the blowdown is to be discharged, the objectives in treating the stream would be to remove suspended solids and to treat by chemical precipitation.

Depending upon the corrosion and scale inhibitors chosen for use in the cooling tower system, additional treatment of the cooling tower blowdown may be desirable before disposal. Systems employing chromate or zinc-based corrosion inhibitors would normally have additional treatment for removal of these compounds. Since the choice of corrosion inhibitors is dependent upon plant operating practices, additional treatment for removal of these inhibitors from cooling tower blowdown was not considered.

If chemical precipitation/coagulation is included in treatment for discharge, a solid waste containing approximately 20 weight percent solids will be produced. This waste will be composed primarily of precipitated inorganic compounds and suspended matter. Disposal of this sludge is discussed in Section 4.3.

Boiler and Process Equipment Cleaning Wastes

Wastewaters which result from the cleaning of process equipment will contain suspended and dissolved solids, trace metals, and organics and could be either acidic or basic. The waste composition will be determined primarily by the cleaning solution and the type of equipment being cleaned. If a surface discharge approach is used, these wastes may be collected in a sedimentation basin for suspended solids removal followed by chemical precipitation and pH adjustment. In this case a chemical precipitation sludge similar to that described earlier (see the cooling tower blowdown discussion) would be produced. Another approach to control of these equipment cleaning wastes is to dispose of them via deepwell injection or surface impoundment.

Plant Process Drain and Storm Drain Effluents

Process drain wastewaters will result from plant process spills, drainage, and leakage that occurs during the operation and maintenance of the system. Process drain flows should be low where good plant housekeeping and maintenance procedures are followed. The stream is likely to contain oil, grease, dissolved organics, suspended solids, and dissolved solids.

Storm drain wastewater is storm water which falls on the plant grounds outside the coal storage area. It will be similar to process drain wastewater but will typically have a much greater peak flow rate and much lower oil and grease levels.

Both of these wastewaters will be collected (separately) and sent to impoundments for sedimentation to allow suspended matter to settle out and to provide surge capacity. Process drain wastewater systems will normally be enclosed between the drains and an initial gravity separation step (such as an API separator) which recovers oil and grease. This practice minimizes fugitive gaseous hydrocarbon emissions and recovers a byproduct oil stream. Additional treatment for process drain wastewaters depends on the amounts and types of contaminants remaining and on the specific reuse options available. Storm water can normally be reused (after sedimentation) directly in the cooling tower or the raw water makeup system.

Secondary Wastewater Streams Containing Primarily Inorganic Compounds

Three secondary wastewater streams which contain primarily inorganic compounds will potentially be present in Lurgi-based synfuels plants. If the plant has a Stretford sulfur recovery unit, then a small Stretford solution purge might be present. Similarly, if the Wellman-Lord sulfur recovery process were used, then a small sulfate purge stream would exist. The third potential secondary wastewater stream of this source type would be blowdown streams from certain gas scrubbers (such as incinerator flue gas scrubbers, catalyst regeneration offgas scrubbers, and the ash lock vent gas scrubber).

Stretford Solution Blowdown--The blowdown stream from the Stretford unit will contain thiosulfates, thiocyanates, sulfates, vanadium compounds, ethylene diamine tetraacetic acid (EDTA), and anthraquinone disulfonic acid (ADA). It may also include other toxic compounds which may greatly impact the treatment methodology. This stream should have a relatively low flow rate.

The objective in treating this stream is to control the discharge of reduced sulfur compounds, organics, and vanadium salts. One approach to treating this stream is reductive incineration. Reductive incineration is a commercially proven process whereby the blowdown stream contaminants are reduced to gaseous H_2S and a solid composed of vanadium compounds and sodium carbonate. The hydrogen sulfide stream is recycled to the Stretford absorber while the solids are recycled to the absorber solution to reduce chemical makeup requirements. The use of this process should greatly reduce or eliminate the blowdown stream from the Stretford unit. An alternative approach to reductive incineration involves acid treatment to oxidize the thiosulfates to a sulfate form which can be concentrated prior to disposal. This process, however, is commercially unproven while reductive incineration of Stretford blowdown has had some commercial experience.

Wellman-Lord sulfate purge--In the Wellman-Lord process a portion of the circulating liquor is purged to control the buildup of sodium thiosulfate, an inert compound which is formed in the process (see Section 4.1). This purge would have a flow rate of approximately 5 m^3/hr for typical synfuels applications and would have the following composition:

Component	wt. %
Water	72.4
Sodium Sulfite	13.8
Sodium Bisulfite	6.9
Sodium Sulfate	4.9
Sodium Thiosulfate	1.0
Sodium Dithionite	1.0

Control measures for this stream include crystallization and combination with other streams for treatment and ultimate disposal. For the cyrstallization approach, the Wellman-Lord process is slightly redesigned so that the water which is removed during drying is returned to the process. The salt formed would be a byproduct or a small volume solid waste. One combination approach involves blending the small stream with a larger stream prior to chemical precipitation (or other inorganic salt removal process) for plants with surface discharge strategies. For plants with deepwell, surface impoundment, or codisposal with ash strategies this concentrated brine stream may be combined with treated and concentrated wastewater from the main treatment train.

Scrubber Blowdown Streams Containing Primarily Inorganic Compounds--The blowdown streams from the various gas scrubbers which may be present (incinerator flue gas, catalyst regeneration offgases, and ash lock vent gas) will all contain primarily suspended solids and inorganic compounds. The catalyst regeneration offgas scrubbers may contain a number of contaminants depending on which catalysts are involved. The shift catalyst offgas will contain large amounts of sulfur oxides along with small amounts of cobalt-molybdenum catalyst fines and possibly other trace elements. The Mobil M catalyst contains cobalt and nickel compounds which may be present in the offgas. The scrubber blowdown will contain the contaminants removed from the offgas including particulates, uncombusted organics, and inorganic salts.

The objectives in treating these various scrubber streams are to remove suspended solids and to treat with chemical precipitation and/or adjust pH if remaining inorganics concentrations are too great for the residual disposal option available.

4.3 SOLID WASTE MANAGEMENT

Many solid waste streams, including ashes, sludges, and spent catalysts, are generated in a Lurgi-based synthetic fuels facility. The available control techniques that are applicable to these streams are identified and evaluated in this section. In comparison with air and water pollution control operations, solid waste management techniques available for a Lurgi-based facility are fewer and also more site specific. In addition, the quantities and characteristics of some solid waste streams (e.g., brines and sludges) are affected by the processes selected for air and water pollution control. Because of this, solid waste management at a Lurgi-based facility is not an isolated issue but rather an element in the total program for pollution control.

The sources and factors affecting the characteristics of the solid waste streams generated in Lurgi-based facilities are summarized in Table 4-72. Of the streams listed, gasifier ash is by far the largest volume stream. Depending on the coal type and synthesis process used, it comprises 48% to 64% of the total solid waste generated from the plant. Flue gas desulfurization (FGD) sludge from lime/limestone processes is the next largest volume stream, comprising up to 21% of the total waste generated. Both of these streams are highly influenced by the characteristics of the coal used.

The type of coal used has considerable impact on the characteristics of the solid wastes generated, and hence the solid waste management techniques used. Major coal properties affecting the solid waste control approaches include: ash content, sulfur content, friability, and ash acidity/alkalinity. Coals with higher ash or sulfur contents will result in the generation of larger quantities of gasifier ash or FGD sludges, and thus will require larger control facilities.

TABLE 4-72. SUMMARY OF SOLID WASTE STREAMS FROM LURGI-BASED INDIRECT LIQUEFACTION FACILITIES

Stream	Stream No.	Pollutants of Potential Concern	Factors Affecting Waste Stream Characteristics
From Main Process Train			
Quenched Gasifier Ash	403	Leachable trace elements, organics	Feed coal characteristics, gasifier operating conditions quench water characteristics.
Spent Shift Catalyst	212	Leachable trace elements	Catalyst life, regeneration frequency, raw gas characteristics
Spent Sulfur Guard	217	Leachable trace elements	Sulfur guard life, regeneration frequency, AGR effluent gas characteristics.
Spent Methanation Catalyst	229	Leachable trace elements	Catalyst life, regeneration frequency, synthesis gas characteristics.
Spent Synthesis Catalysts	222 218 223	Leachable trace elements	Catalyst life, regeneration frequency, synthesis gas characteristics.
Tars and Oils	111 112	Higher aromatics, POM, mercaptans, HCN	Feed coal characteristics, gasifier operating conditions, tar/oil removal process design and operating conditions.
From Auxiliary Processes			
Boiler Bottom Ash	406	Leachable trace elements	Feed coal characteristics, boiler operating conditions, slurry water characteristics.
Raw Water Treatment Sludges	300	Leachable trace elements	Raw water characteristics, treatment system design and operation.

(Continued)

TABLE 4-72. (Continued)

Stream	Stream No.	Pollutants of Potential Concern	Factors Affecting Waste Stream Characteristics
From Pollution Control			
Boiler Fly Ash	441	Leachable trace elements, potential dust emissions	Feed coal characteristics, boiler operating conditions, slurry water characteristics.
FGD Sludges from Boiler[a]	444	Leachable trace elements	Coal sulfur content, FGD process design and operation.
Spent Claus Catalyst	413	Leachable trace elements	Catalyst life, regeneration frequency, acid gas characteristics.
Biological Sludge from Wastewater Treatment	431	Leachable organics, trace metals	Gas liquor characteristics, wastewater treatment system design and operation.
Dewatered Chemical Precipitation Sludges	433	Leachable trace elements	Gas liquor characteristics, wastewater treatment system design and operation.
Recovered Sulfur	116	Vanadates, thiocyanates (with Stretford only)	Coal sulfur content, gasifier operating conditions, sulfur recovery unit design and operation.
Collected Dust from Particulate Control	400	Potential dust emissions	Dust collection process design and operation.

[a] For the wet limestone process.

Friability of coal is dependent upon the clay and mineral contents of the coal. During coal preparation operations, highly friable coals (coals with low clay contents) will generate large quantities of coal fines which are too small to be used as feed to the Lurgi gasifier. The energy value of the coal fines may be recovered by using them as boiler fuel or to produce additional synthesis gas in a gasifier capable of handling fines. However, coals that generate excess coal fines (i.e. more than can be used) may have to dispose of them by landfilling.

The gasifier and boiler ash generated may be acidic or alkaline. Alkaline fly ash has been used in existing power plants to mix with FGD sludges before disposal. Mixing these two may result in a material structurally more suitable for landfilling. The acid/alkaline nature of ashes may affect their leaching characteristics and thus influence control practices.

The solid waste streams listed in Table 4-72 can be classified according to four waste type categories (source types) which are based on the nature of the waste. These waste types are: inorganic ashes, recovered unsalable byproducts, organic sludges, and spent catalysts. Several control techniques are potentially applicable to these streams.

In general, solid waste control techniques aim at containing the entire waste stream. Thus, the performance of these techniques, in terms of removal or control efficiencies, is generally 100 percent. However, unless designed and operated properly, secondary waste streams with undesirable characteristics may be generated and migrate away from the site employing the technique. For example, runoff can contaminate surface water and percolating water can contaminate groundwater. The significance of this depends upon the nature of the species which might be leached out of the solids by the runoff/percolation. Thus, in selecting solid waste management techniques, the major evaluation criteria are whether the secondary waste streams are suitably contained.

Section 4
Solid Wastes

Based upon current techniques practiced in synfuel and other industries, together with those being considered by proposed synfuel plants, the bulk of the solid waste from Lurgi facilities will likely be disposed of on land. Land-based disposal techniques are by far the most site-specific techniques. The suitability of the site, as well as the design and operation of the facility, would depend on the site location, transportation costs, hydrogeologic conditions, and many other factors. In short, a detailed analysis of the specific site is an important element of the overall control technique evaluation process.

Land disposal (e.g., landfill, surface impoundment, land treatment) will be subject to regulations promulgated by EPA pursuant to the Resource Conservation and Recovery Act (RCRA), covering the generation, transport, treatment, storage, and disposal of solid wastes. Requirements concerning a solid waste can vary significantly, depending upon whether the waste is determined to be "hazardous" or "non-hazardous" as defined by RCRA regulations. In this manual, no attempt is made to judge whether the various individual waste streams will be determined to be hazardous or not. Rather, treatment and disposal techniques are presented which would cover the range of possibilities, whether the waste is hazardous or non-hazardous.

Another technique potentially applicable to some solid waste streams - in addition to land disposal - is incineration. If a waste which is determined to be "hazardous" is proposed for incineration, the incinerator will have to be designed and operated in accordance with RCRA requirements.

The available techniques that may apply to the Lurgi solid waste streams are identified and evaluated in this section. Since no specific site is being considered, a general overview of these techniques is first presented. This is followed by an evaluation of the applicable controls to each individual stream under each waste source type. The emphasis is on identifying the applicability of the technique. For the reasons stated above and because the characteristics of many of the solid waste streams are not known, it is not possible in this manual to evaluate the optimum design and operation of these techniques; optimum design/operation will vary with the site. It is assumed that solid waste management facilities are captive, i.e., they only handle wastes from the Lurgi plant.

4.3.1 Solid Waste Control

Several control techniques are potentially applicable for management of solid waste streams. These techniques are summarized in Table 4-73. As shown, they can be broadly divided into three control categories according to their functions. The three control functions are treatment, reuse/resource recovery, and disposal. Treatment may involve specific chemical/physical processes for preparing the waste to meet certain reuse/resource recovery specifications or to stabilize the waste for disposal. Reuse/recovery is one form of ultimate or final control for the waste. This approach is usually waste-specific, highly dependent on market availability and cost tradeoffs, and may require specific treatment of the waste. Disposal is another form of ultimate control for the waste. Most disposal techniques are land-based techniques and thus are highly site-specific. The major site-specific factors that affect the design, operation, and cost of land-based techniques are summarized in Table 4-74. The following is a brief description of the individual techniques.

TABLE 4-73. SUMMARY OF SOLID WASTE MANAGEMENT TECHNOLOGIES

Technology	Description	Operational Considerations	Reliability or Limitations	Equipment	Waste Generated	General Comments
Treatment						
Fixation/ Encapsulation	Chemicals are added to stabilize or solidify the wastes	Wide variety of wastes can be processed; the feasibility of solidifying a particular waste may differ with different processes	Limited commercial experience	May include mixing chamber, pumps, metering devices, storage tanks, chemical feed system	Solidified waste	Most processes are applicable only to small waste streams
Incineration	Organic wastes undergo destruction to reduce volume and toxicity	Each type of organic waste may require different operating characteristics; experienced operators required	Only organic wastes can be processed	Waste transportation machinery, incinerator	Ash; air pollution control residues	Process is energy intensive
Reuse/Resource **Recovery**	Waste is utilized in a manufacturing process, construction application, or is processed for reuse in original application	User for waste must be located; cessation of reuse requires immediate alteration of management techniques; thereby, necessitating long-term contracts	Markets for wastes are limited and economic viability is heavily influenced by distance to market	Transportation vehicles	None	Most environmentally acceptable management technique
Disposal						
Landfill	Site is designed, constructed, and operated to totally contain waste; features include natural or artificial liners, leachate collection systems, and groundwater monitoring system	Wide variety of wastes can be accepted; provisions must be made for incompatible wastes and reactive wastes	Wastes will be contained subject to adequate site operation and maintenance and absence of extreme hydrogeological changes or earth movements	Earth moving equipment, waste handling machinery such as forklifts and trucks	Surface runoff and leachate	Site location and design dependent upon hydrogeological conditions; provisions must be made for site care after cessation of operations
Surface Impoundment	Site is excavated or diked to form pond to contain waste; supernatant is syphoned off and treated or allowed to evaporate	Similar to landfill	Similar to landfill	Machinery to move waste to site, usually pipelines	Supernatant and leachate	Waste may have to be removed when operation ceases; if waste remains, long-term site care and maintenance program must be established
Land Treatment	Waste is treated by incorporation into the land according to specific procedures	Only limited types and mass of organic wastes can be managed	Heavily dependent upon weather conditions	Waste moving machinery, usually trucks, and waste incorporation machinery, usually bulldozers and discs	Possibly surface runoff and leachate	Site location dependent on soil conditions; provisions must be made for long-term site care

TABLE 4-74. SITE-SPECIFIC FACTORS TO BE CONSIDERED FOR TERRESTRIAL DISPOSAL OPTIONS

Climatological

- Wind conditions (e.g., speed, directional flux, dilution factors, humidity, temperature, etc.)
- Precipitation (e.g., annual precipitation, storm intensity, snow contributions, etc.)
- Evapotranspiration rate (e.g., season variations)

Geologic Factors

- Physiographic features (e.g., runoff coefficient, slope, drainage patterns, erosional features, etc.)
- Surface and subsurface geology (e.g., outcrops, bedrock features, strike and dip of the bedrock, rock composition, etc.)
- Soil types (e.g., CEC capacity, texture, permeability, stratification, homogenous vs. heterogenous deposition, chemical composition, percent of humic material, etc.)
- Seismic factors (e.g., ground shaking or rupture)

Hydrogeologic Factors

- Drainage patterns
- Stream flow (e.g., velocity, perennial vs. intermittent, effluent or influent source, etc.)
- Surface waters (e.g., tidal effects, recharge vs. discharge points)
- Vadose zone (e.g., depth, moisture content, hysteresis patterns, storage capacity, etc.)
- Groundwater (e.g., depth, number of aquifers and relationships, confined or artesian, nature of confining layer(s), capillary fringe characteristics, etc.)
- Piezometric surface (e.g., streamline flux patterns due to seasonal or event related phenomena, influence of recharge/discharge areas, streamline anomalies, etc.)
- Water quality (e.g., background vs. undersite vs. downgradient, water uses - consumptive, irrigation, recreation, point source contributors and their respective hydrogeologic pathways, etc.)
- Floodplain (100 year flood) (e.g., aerial flooding limits, degree of localized streamline pattern reversal, erosional consequences, etc.)
- Wetlands (e.g., recharge vs. discharge source, wetland/groundwater continuity and pathway)
- Recharge and discharge areas (e.g., proximity to disposal area, volume of flow)

Land Use Factors

- Historic significance
- Transportation corridor (access)
- Beneficial uses
- Cost
- Demographic setting
- Geopolitical impact
- Ultimate land use

4.3.1.1 Treatment

For the purpose of this manual, only two solid waste treatment techniques are considered. These are fixation/encapsulation and incineration. Other techniques such as dewatering and neutralization are either considered as part of the base plant operation, or part of the pollution control processes in other media (air or water), depending on the origin of the waste.

Fixation/Encapsulation

Fixation and encapsulation are treatment processes which stabilize or solidify waste constituents, or enclose the waste within other materials. Fixation processes generally combine the concepts of solidification (the alteration of the characteristics of a waste to attain desired structural characteristics) and stabilization (the immobilization of waste constituents by chemical reactions to form insoluble compounds or by entrapment within an inert polymer or stable crystal lattice). Depending on the principal chemical agents used, fixation processes can be categorized as cement-based, lime-based, thermoplastic organic polymer, and glassification techniques. Encapsulation processes involve enclosing the waste in a coating or jacket of an inert, relatively impermeable material so that contact between the waste and water is prevented. Regardless of the specific chemicals used, typical fixation process operations involve mixing the chemical with the waste in a reactor at a specific temperature and for a specific time period. The end product is the fixed or encapsulated waste. In the case of encapsulation, bulk wastes are enclosed in a stabilizing shell or container rather than being intimately mixed with a stabilizing agent.

In principle, these processes are applicable to treating any waste by applying "sufficient" chemicals. In practice, for economic reasons these techniques have only been applied to small volume waste streams or streams which are prone to pozzolanic reactions. Chemical requirements for fixing the latter type of streams are generally low. FGD sludge is one example of this type of stream. Several proprietary, cement- or lime-based fixation techniques have been used in fixing FGD sludges. Typical unit costs are reported to be $11 to $17 per metric ton of sludge fixed (80,81,82,83). Before using these techniques for a specific waste, detailed treatability studies with various chemical additives should be performed to: 1) establish that the waste is treatable, 2) select the optimal process, and 3) minimize the cost (80).

Incineration

Incineration is a controlled thermal decomposition process which reduces the weight and volume of the waste by converting many component elements of organic matter into gaseous forms. The extent of volume and weight reduction is dependent upon the waste characteristics, the incineration process, and equipment used. Incineration is also a viable detoxification process if the toxicity results from the structure of the organic material as opposed to the properties of the elements it contains (84). The end products of incineration include carbon dioxide, water, ash, and other inorganic compounds. Incineration has been applied to various industrial wastes including refinery wastes, sewage sludge, paper mill waste liquor, pharmaceutical wastes, and organic chemical wastes. The common types of incinerators used for solid waste disposal include rotary kilns, multiple hearths, and fluid bed reactors. The annualized unit cost for a 1.0×1.0^7 kcal/hr capacity multihearth incinerator is estimated to be $350/Mg.

4.3.1.2 Reuse/Resource Recovery

Reuse or resource recovery of waste streams is desirable from an environmental standpoint because of direct waste reduction and perhaps displacement of other resource requirements. Potential adverse environmental impacts associated with disposal of the waste are eliminated although other impacts may arise as a result of the reuse/recovery process utilized. This control approach is highly waste-specific and is constrained by the availability of markets or uses for the waste. Available reuse/resource recovery alternatives will be identified as part of each specific waste stream discussion.

The economics of reuse/resource recovery are sensitive to site-specific factors such as transportation costs and some general factors such as the prices of the recovered/reusable materials and the cost of preparing the waste for reuse/resource recovery. The feasibility of this control should be thoroughly analyzed for each individual facility before implementation.

4.3.1.3 Disposal

The bulk of the solid wastes from Lurgi facilities are likely to be disposed of on land. Three potentially applicable land disposal techniques for these streams are discussed in this section. These are landfill, surface impoundment, and land treatment.

Landfills

Landfills have been widely used for the disposal of municipal refuse and a range of industrial wastes. In landfilling, waste is brought to the disposal site by truck or conveyor, spread in layers, and compacted with heavy equipment. In most landfills the waste is covered with a thin layer of soil at the end of the working day. The process is repeated until the desired depth is reached or the available area is filled. A final cover of soil is then added. The finished site is either revegetated or prepared for other end uses.

Landfill can be accomplished in unexcavated depressions (the area-fill method) or in excavated sites (the trench-fill method). These can be natural sites or man-made sites such as coal mines. There are two major concerns in landfill design and operation. Runoff from landfill sites may contaminate surface water, and percolation from sites, after passing through the waste pile, may contaminate groundwater. Runoff/surface water contamination may be prevented by grading the site and by containment of runoff. Diversion channels should be incorporated into the initial design of the landfill and constructed before the site begins accepting waste (85). This prevents surface runoff water from entering the site and generating leachate.

Migration of leachate from the site can be controlled by lining the landfill with clay, concrete, asphalt, or plastic. Liners will often be required if the solid waste is considered to be hazardous and may at times also be desirable if the waste is nonhazardous. The choice of an appropriate liner or liners will depend on 1) site-specific climatologic, geologic, and hydrogeologic factors, 2) the compatibility of the liner and the waste to be contained, and 3) the relative cost of compatible liners. A leachate collection and treatment system may also be necessary. Such systems consist of perforated pipes and sumps placed in a layer of permeable sand at the bottom of the fill. After being pumped out of the landfill, the collected leachate may be treated in the gasification facility's wastewater treatment system or in a separate treatment system (86).

In the absence of any judgment concerning whether or not a given waste might ultimately be determined to be hazardous, and in order to remain independent of site-specific factors, two landfill designs are considered in the PCTM. These two designs cover the range from the simplest set of conditions (nonhazardous waste and favorable site conditions that preclude the need for liners) to the most complex (hazardous waste and unfavorable site conditions which necessitate double liners). The two landfill designs are presented in Figure 4-18. For the purpose of this assessment, the lined landfill design assumes an upper liner consisting of 1 m of clay and a lower liner of 0.76 mm synthetic material. Both landfill designs assume the completed fill will be 30 m above the original land surface with a slope of 3:1. Both landfills will have a final cover consisting of 0.5 m sand and 0.3 m of clay. The most complex, hazardous case would also include provision for closure and post-closure care, monitoring, record keeping, and other requirements.

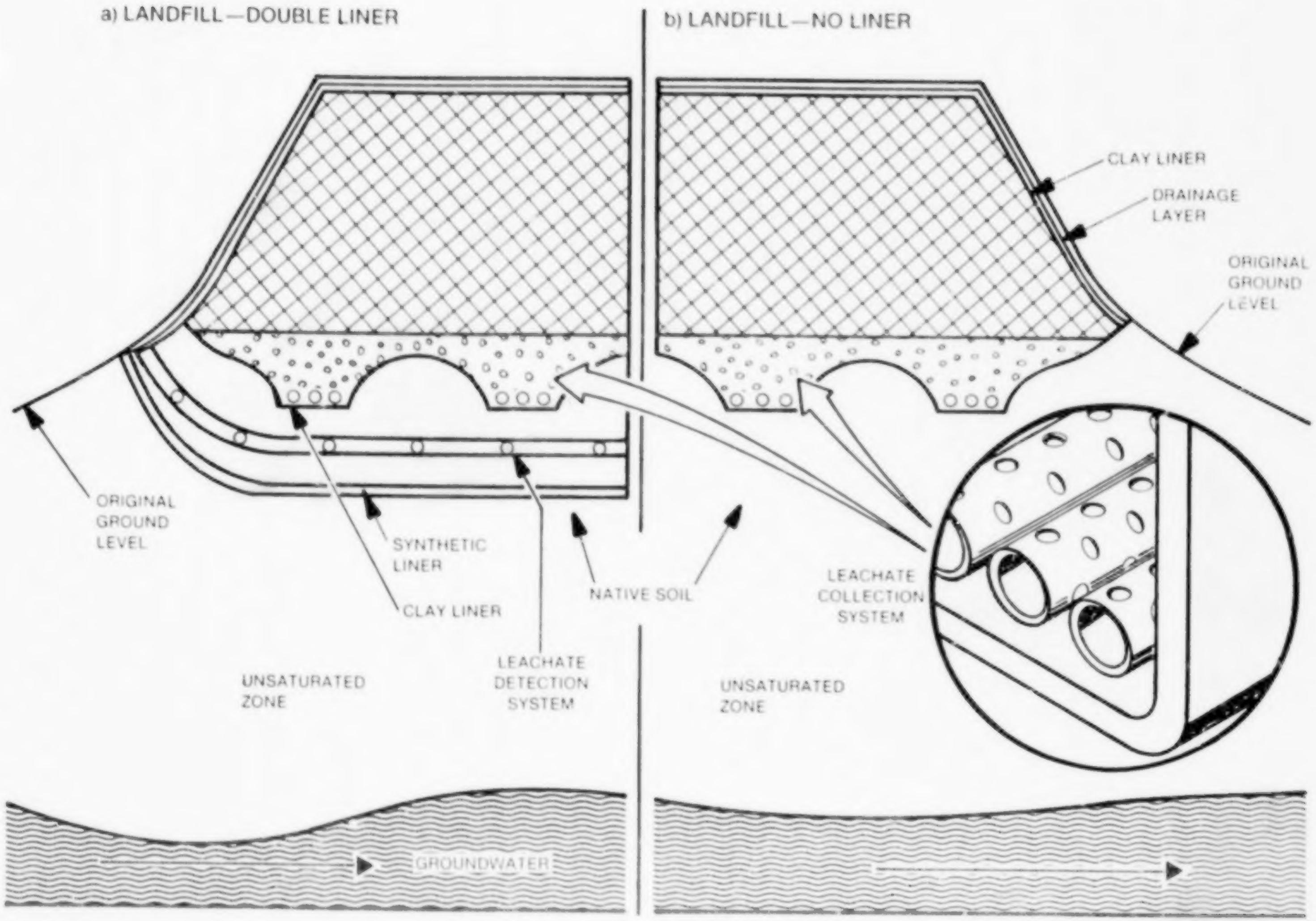

Figure 4-18. Landfill designs

The total capital investment and annualized unit costs as a function of the site capacities for the two designs are presented in Figure 4-19. The capital investment estimates include site preparation costs (e.g., cleaning and scrubbing, groundwater monitoring and collection, liners), final cover and revegetation costs, and landfill equipment costs. It was assumed no excavation is required. The annualized costs include labor, fuel, and amortized capital costs, but do not include hauling costs and other costs such as administrative, closure/postclosure, and liability costs. These other costs would depend on the classification of the disposed wastes under RCRA. EPA has estimated that for a 50,000 Mg/yr commercial hazardous waste landfill, administrative and other compliance costs amount to $9/Mg (87). Hauling costs are a function of distance between the plant and the disposal site. It is estimated that the unit costs for a roundtrip distance of 5 and 15 km are $2 and $4/Mg, respectively.

Land costs are not included in the cost data in Figure 4-19. About 1,100,000 m^2 of land is required per 106 Mg/yr of waste generated. Assuming a land cost of $5,000 per 10,000 m^2, the capital investments for the lined and unlined landfills, as presented in Figure 4-19, will be increased by more than nine percent. Additional land may be required for road construction, buffer zone, buildings, etc.

Surface Impoundments

Surface impoundments have been utilized widely by municipalities and industries to process or dispose of waste liquids, sludges, and slurries. Like landfill sites, the impoundments can be in natural depressions or in excavated areas. Earthen dikes are usually constructed around the impoundment area. Wastes are usually transported hydraulically to the impoundment. While the wastes deposit at the bottom of the impoundment, the supernatant may be removed and treated for discharge or recycle or allowed to evaporate.

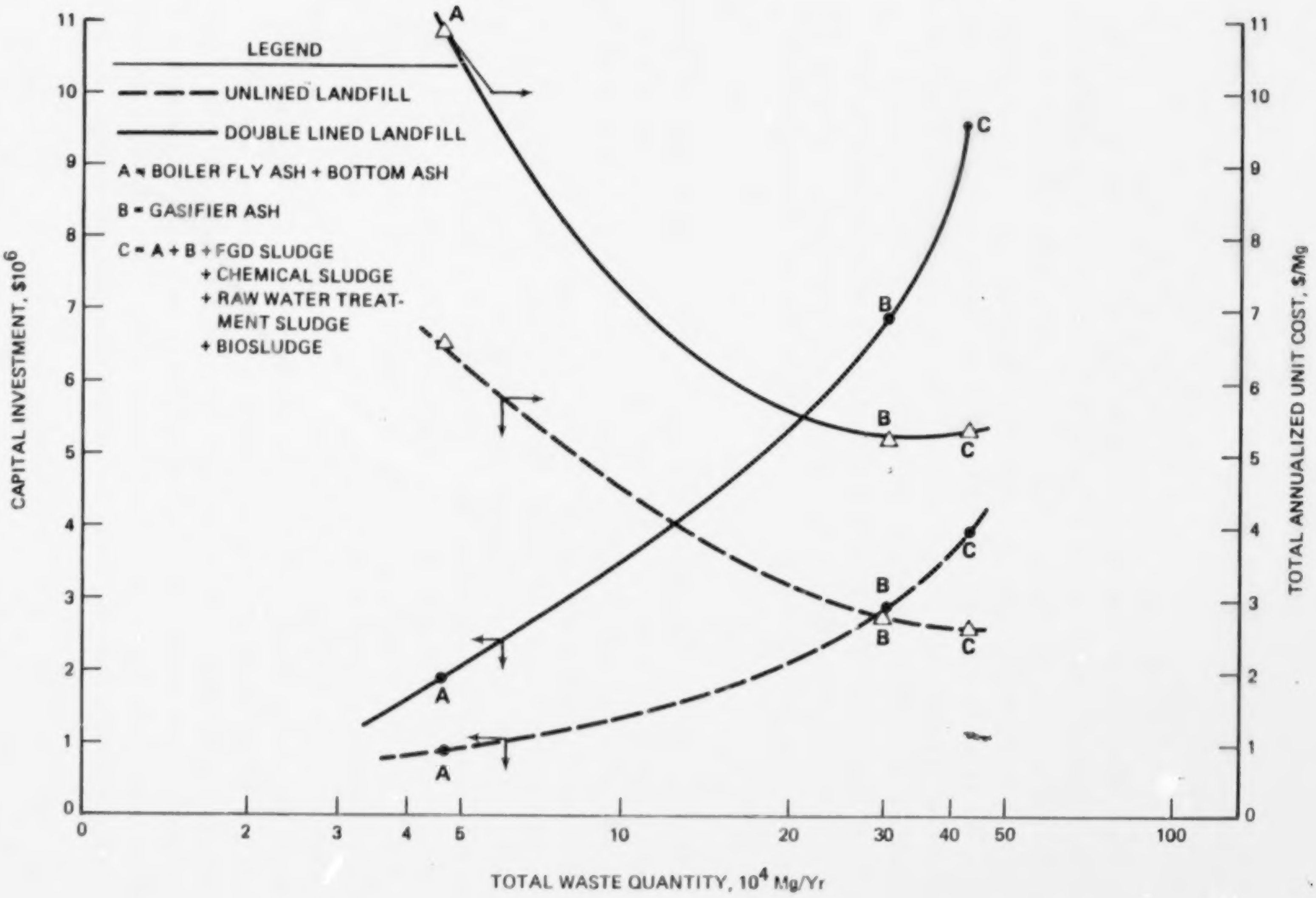

Figure 4-19. Capital investment and annualized unit cost for landfills

Leachate migration from surface impoundments is controlled in much the same way leachate from landfills is controlled. Diversion structures prevent runoff from entering the site, while liners of in-place or compacted soils or synthetic materials retard leachate migration down into the soil and groundwater. As in the case of landfills, the PCTM considers both an unlined and a double-lined impoundment in order to cover the range of possible experience. The unlined impoundment represents the simplest set of conditions (non-hazardous waste and favorable site conditions that preclude the need for liners). The lined impoundment represents a much more complex situation (hazardous waste and unfavorable site conditions that necessitate a double liner system).

When the surface immpoundment has been filled with waste, the site may be closed in one of two ways: the waste may be left in place and covered with clay and sand to prevent erosion and the infiltration of precipitation, or it may be removed from the impoundment site for further treatment or final disposal in a landfill (88). If wastes are left in place, the site becomes a landfill (subject to any requirements pertaining to a landfill), and a long-term site care and maintenance program will probably need to be established. The cost per unit volume for surface impoundments is expected to be similar to those of landfills with similar depths. However, since surface impoundments generally are used for the disposal of wet, not yet dewatered wastes, a larger area may be required, per unit mass of dry solids, resulting in higher disposal costs (i.e. some of the disposal area will be for disposing of water). Disposal costs could be reduced if the wet wastes were dewatered first, but there would be costs associated with dewatering. Similarly, disposal costs may be reduced if appreciable natural dewatering occurs within the surface impoundment due to settling and evaporation. This trade-off in cost is highly dependent upon the waste characteristics and site-specific factors.

Land Treatment

Land treatment refers to the use of land or soil as a medium to treat and dispose of waste. Also known as landfarming, landspreading, and soil application, land treatment has been practiced successfully for the treatment and disposal of municipal wastewater treatment sludges and petroleum industry oily wastes for many years. It relies on the ability of naturally occurring soil microorganisms to decompose and utilize organic compounds under aerobic conditions. The design and operation of land treatment systems would be affected by whether or not the wastes were considered to be hazardous.

Wastes added to soil are subject to one or more of the following processes: 1) decomposition/degradation; 2) leaching; 3) volatilization; and 4) incorporation into the soil matrix (e.g., through ion-exchange or adsorption). It is the degradation processes which treat the waste to reduce its objectionable properties; these processes must be maximized during land treatment, while the other processes must be minimized or eliminated. Applying biodegradable wastes, maintaining proper (aerobic) conditions for microbial action, and avoiding or pretreating wastes which are toxic to the microorganisms will encourage degradation processes. Proper site selection will minimize leaching and subsequent contamination of surface waters or groundwaters. If volatile wastes are to be land-treated, subsurface injection of the wastes or immediate tilling after application will minimize air pollution.

Wastes with high concentrations of toxic substances such as arsenic, cadmium, lead, and mercury should not be land treated in sites where food chain crops are grown, as they may be incorporated into the soil and taken up by plants (89). Prior to land treating wastes, long term studies should be performed to confirm that the waste is degradable in the soil, that there is no accumulation of nondegradable toxic substances in the soil, and to establish the area required for the particular soil-waste combination.

Assuming biosludge is applied 10 times/yr, with an application rate of 0.015 Mg/m^2/application, and a factor of 2 to account for land required for roads, buffer zones, dikes, etc., it is estimated that 20,000 m^2 of land is required to land treat 15,000 Mg/yr of biosludge. The annualized unit cost for this is estimated to be $7.6/Mg.

4.3.2 Inorganic Ashes and Sludges

Inorganic ashes are the largest volume solid waste type from a Lurgi-based plant. Waste streams in this waste type include gasifier ash, boiler bottom ash, boiler fly ash, FGD sludges, dewatered chemical treatment sludges, and raw water treatment sludges. The application of the available control techniques to these streams are evaluated in this section.

4.3.2.1 Gasifier Ash

Gasifier ash consists of the inorganic, noncombustible portion of the feed coal. This is the single largest volume solid waste stream in a Lurgi facility; the flow rate of this stream (for the Rosebud coal case) is estimated to be 38.3 Mg/hr. As discussed in Section 3, this stream is essentially coal ash. Gasifier ash leachate may contain low levels of trace elements. Tests of leachate for organics have not been conducted but organic levels would be expected to be low. The following treatment, reuse, and disposal techniques are applicable to this stream.

Treatment

The techniques applicable to treatment of gasifier ash are fixation and encapsulation. Treatment of gasifier ash may be appropriate if future data indicate that significant concentrations of trace metals are detected in leachate from the gasifier ash. Currently available leachate data indicate the trace elements in the leachate are low and should not be significantly different from commercial coal boiler bottom ash.

The performance of treating this stream is dependent upon the specific process (additive agent) used, and can only be established after thorough treatability studies. The cost for treating this stream is also dependent upon the process used. Assuming that the fixation processes which have been applied to FGD sludge are applicable to treating this stream, the unit cost will be about $11-$17 per Mg (80,81,82,83).

Reuse/Resource Recovery

Gasifier ash may be utilized in a number of commercial applications, just as boiler bottom and fly ash from fossil-fueled power plants have been used. The National Ash Association reported that 24.3 percent of the coal boiler ash produced in 1977 was reused in commercial applications (90). Ash has been used commercially as a partial replacement for cement in concrete, as fill material for roads and other construction projects, and as blast grit and roofing granules. This alternative is likely to be applied only to ashes that are collected dry. The cost of drying the quenched ash may be prohibitively high. In addition, quenching the ash may change its properties, making it unfit for reuse and negating this option in certain cases.

The major constraints on reuse of gasifier ash are those of the market for the material. Market conditions will vary from site to site. Given the fact that not all ashes from existing power plants are commercially utilized, it may be difficult to find markets where all or significant quantities of the ash from a Lurgi facility can be reused. Users for the ash will likely be limited to those who are located in the vicinity of the plant. The economic viability of reuse decreases with increasing distance to market and hence increasing transportation costs. If market conditions change so that commercial reuse ceases, the waste management techniques for the ash will need to be altered. Long-term contracts with users may lessen the potential for market interruptions.

Disposal

Gasifier ash can be disposed of in landfills or in impoundments.

Landfill-- In landfilling, gasifier ashes are usually brought to the site by trucks, spread on the surface of land or previously placed ashes, and compacted. As the pile height increases, a working face with safety slope (assumed to be 3:1) is developed to ensure stability of the fill.

If the gasifier ash is determined to be nonhazardous, an unlined landfill might be possible in the most favorable case (e.g. favorable site conditions). On the other hand, if the wastes were considered to contain hazardous components, a lined landfill would be necessary where hydrogeologic or other site factors are unfavorable.

Based on current and proposed practices in synfuel and other industries, this stream is likely to be codisposed with other solid waste streams from the plant in one common landfill. Although more than one landfill/disposal facility (e.g., one landfill design for hazardous waste and one landfill for nonhazardous waste) may be operated in a Lurgi facility, for costing purposes in the PCTM, one landfill accepting the wastes from the Lurgi plant is assumed. By considering the alternatives of all wastes being disposed of in a nonhazardous waste landfill with no liner and in a hazardous waste landfill with double liners, the range of landfill cost estimates in the PCTM should bracket the costs that might be encountered in practice for any split of the wastes between hazardous and nonhazardous categories.

Assuming a landfill is designed to accept the gasifier ash, boiler bottom and fly ash, FGD sludge, and raw water treatment sludges, the capacity of the landfill would be 420,000 Mg/yr for the Rosebud coal case. As shown in Figure

4-19, the annualized unit costs for the unlined and lined landfill designs will be $2.7/Mg and $5.3/Mg, respectively. The total annualized costs that would be attributable to the gasifier ash stream would be $815,000/yr and $1,600,000/yr, respectively, for the two landfill designs.

If the gasifier ash were disposed of by itself in a separate, dedicated landfill, annualized unit costs for this smaller landfill (302,000 Mg/yr) would be $2.8/Mg and $5.3/Mg for a nonlined and lined landfill, respectively. The total annualized cost for this case would be $850,000/yr and $1,600,000/yr, respectively.

Surface Impoundment-- One major difference between disposing of gasifer ash in a landfill and a surface impoundment is the means of transporting the ash to the disposal site. Surface impoundments are usually used for storage or disposal of wet ashes which are transported hydraulically to the impoundment in a fluid state. For storage impoundments, the ashes are dredged periodically and disposed of in landfills. For disposal impoundments, the ashes are left in place and are covered to prevent erosion and infiltration of precipitation. The unit costs for surface impoundments are similar to the costs of landfilling, assuming that no excavation is required. The total disposal costs may be higher because surface impoundments generally are used for the disposal of wet, not yet dewatered wastes. Hence, extra capacity is needed for the water content in the waste.

4.3.2.2 Boiler Bottom Ash

The flow rate of this stream is estimated to be 1.3 Mg/hr for the Rosebud coal case, assuming 15% of the total feed coal to the plant is used as feed to the boiler. The treatment, reuse, and disposal techniques for this stream would be similar to those for gasifier ash. Where landfill is the technique selected this stream is likely combined with other solid waste streams and disposed of in one common landfill. As discussed in Section 4.3.2.1, annualized unit costs for landfilling the solid waste streams in a common landfill are estimated to be $2.7/Mg and $5.3/Mg, respectively, for a non-lined and lined landfill. Based on these unit costs, the annualized disposal cost attributable to this stream would be $28,000/yr and $54,000/yr, respectively.

4.3.2.3 Boiler Fly Ash

The flow rate of this stream is estimated to be 5.2 Mg/hr for the Rosebud coal case, assuming 15% of the feed coal to the plant is used as feed to the boiler. Available technology requires that gasifier ash and boiler bottom ash be quenched before any subsequent handling or disposal. Boiler fly ash, however, may be collected and handled dry (via a dry ESP or baghouse) or wet (via a wet ESP or scrubber). The choice of collection technology depends in part on site-specific disposal factors and also on factors specific to coal type. Some fly ashes tend to undergo fixation reactions when wetted, much as Portland cement does.

Recently, more power plants began converting to dry collection systems for boiler fly ash. When boiler fly ash is collected and handled entirely in the dry form, it can be potentially recovered as a resource. The available management techniques are similar to those discussed under the gasifier ash section. Where landfill is the technique selected, this stream is likely combined with other solid waste streams and disposed of in one common landfill. As discussed in Section 4.3.2.1, annualized unit costs for landfilling the solid waste streams in a common landfill are estimated to be $2.7/Mg and

$5.3 Mg, respectively, for a non-lined and lined landfill. Based on these unit costs, the annualized costs attributable to this stream would be $110,000/yr and $220,000/yr, respectively.

4.3.2.4 Boiler FGD Sludge

The flow rate of this stream is estimated to be 7.8 Mg/hr for the Rosebud coal case, assuming 15% of the total coal feed to the plant is used as feed to the boiler. Applicable techniques for controlling FGD sludge include fixation, surface impoundment, and landfills. These techniques have been widely used in disposing of FGD sludge from existing coal-fired power plants.

Treatment - Fixation

FGD sludge typically contains 30 to 50 percent solids after thickening or filtration. It is not a good landfill material in this form because it is thixotropic. To rectify this problem, treatment by fixation may be practiced. Several patented processes are available commercially for fixing FGD sludges. One mixes the sludge with boiler fly ash and lime while another adds a proprietary chemical (basically a cementitious agent) as the hardening material. Typically these proprietary processes involve dewatering the sludge and combining the sludge with proprietary additives which promote pozzolanic reactions, resulting in a material less leachable, less permeable, and structurally more suitable for landfill. Proprietary methods which have been successfully applied to fixing FGD sludges include Chemfix (addition of Portland cement and sodium silicate), Calcilox (calcined blast furnace sludge and lime), IUCS - Poz - O - Tec (fly ash and lime under controlled temperature and moisture conditions), ICT (lime, bentonite, and cement), and Research - Cottrell (sludge dewatering prior to fly ash admixing).

Unit costs for these treatments range from $11 to $17 per Mg of dry solids (80,82). Another treatment alternative practiced in many coal-fired power plants is mixing the FGD sludge with boiler bottom and fly ash before disposal. For coals that generate ashes that are alkaline, mixing the ash with the sludge will also initiate pozzolanic reactions.

Disposal

Disposal techniques applicable to FGD sludge include landfill and surface impoundment. Because of its low solids content and structural instability, FGD sludge may be treated by fixation or mixing with boiler fly ash prior to disposal. The use of surface impoundments will reduce the liquid content of the sludge, but the dried solids are readily soluble when exposed to moisture after disposal, so proper surface impoundment closure will be essential.

Assuming this stream is mixed with fly ash and other inorganic ashes before disposal in a common landfill, the annualized unit costs for a nonlined and lined landfill are estimated to be $2.7/Mg and $5.3/Mg, respectively (see Section 4.3.2.1). The annualized cost attributable to this stream would be $170,000/yr and $330,000/yr.

4.3.2.5 Dewatered Chemical Precipitation and Raw Water Treatment Sludges

The applicable treatment and disposal techniques for this stream would be similar to those for the FGD sludge, except that the optimum fixation process and hence the treatment costs may differ. Where landfill is the technique selected, this stream is likely codisposed with other solid waste streams in one common landfill. Assuming unit costs of $2.7/Mg and $5.3/Mg respectively, for a nonlined and lined landfill, disposing of dewatered chemical precipitation sludge will cost $8,500/yr and $17,000/yr, while disposing of dewatered raw water treatment sludge will cost $4,000/yr and $8,000/yr.

4.3.3 Recovered Byproducts

This source type includes elemental sulfur recovered from the bulk sulfur removal processes, excess coal fines, and collected dust from particulate control.

4.3.3.1 Recovered Elemental Sulfur

Recovered elemental sulfur can be sold as a byproduct. However, the sulfur may be contaminated with carbonaceous impurities (from Claus plant) or vanadates, thiosulfates, and thiocyanate salts (from Stretford plant), making it non-marketable without further in-plant processing. If the sulfur cannot be sold, it can be disposed of in landfills.

There is a potential for elemental sulfur to be oxidized in a landfill environment and such oxidation result in acid generation. Acidic leachate could solubilize trace elments from other wastes in the landfill. Hence, it may be desirable to dispose of waste elemental sulfur with alkaline wastes such as FGD sludges.

4.3.3.2 Excess Coal Fines

Excess coal fines are the small particles of coal (underflow from the secondary screening process) that are produced in excess of steam boiler feed requirements. Applicable treatment, reuse, and disposal techniques are described below.

Treatment

Excess coal fines may be treated so that they can be reused as gasifier feed. This treatment consists of blending the coal fines with a binder (e.g., bentonite) and forming this mixture into pellets by forcing it through a die and cutting it into pieces of the desired length. The resulting pellets are approximately 2.5 cm in diameter and 5.0 cm in length.

Reuse

Excess coal fines may be combusted onsite to generate excess steam or power for export. Excess coal fines can also be gasified in a gasifier which can accept fine coal particles as feed (such as the Texaco or GKT gasifier) in order to produce additional synthesis gas. A third option is to sell the excess coal fines to offsite users (e.g., coal-fired power plants). The third option will depend on prevailing market conditions. The potential of this option is further constrained because the transportation of coal particles less than 0.9 cm in diameter presents safety problems and results in high losses unless closed containers are used. Since these containers are not widely used for coal transportation, significant delivery costs could be incurred.

Disposal

Excess coal fines can be disposed of in landfills. In the actual disposal operation, spraying the fines with water or some other means of dust control may be necessary.

4.3.3.3 Collected Dust from Particulate Control

This secondary waste stream consists primarily of coal dust emissions collected throughout the gasifier installation. This dust may be treated, reused, or disposed of with the excess coal fines.

4.3.4 Organic Sludges

This waste category includes one stream, namely, biosludge from the biological treatment process. The flow rate of this secondary waste stream has been estimated to be 1.9 Mg/hr for the Rosebud coal case.

4.3.4.1 Treatment

Although no data are currently available on the composition of this waste, it is highly probable that some of the nonbiodegradable toxic organics that might have been present in the raw process liquor (such as polyclic organics and aromatic amines) will end up in the sludge through sorption. These organics can be destroyed by incineration.

Incineration

Incineration of municipal and industrial biological oxidation sludges has been practiced for many years. The application of this treatment technique to this organic sludge could be expected to destroy greater than 99% of most organics and reduce the quantity of waste that requires ultimate disposal. Assuming the biosludge is 20% solids and 70% of the solids are volatile, the total waste quantity will be reduced by 94% through incineration.

Table 4-75 presents the estimated costs for incinerating the biosludge in a rotary kiln incinerator (1.0 x 10^7 kcal/hr) with energy recovery. The heating value of the biosludge was assumed to be 5,500 kcal/hr. As shown in Table 4-75 the capital investment for incineration is estimated to be 10 to 12 million dollars; the total annualized cost is 5.2 million dollars per year, or about $350/Mg.

TABLE 4-75. ESTIMATED TREATMENT/DISPOSAL COST FOR BIOSLUDGE

Item	Incineration	Land Treatment
Total Capital Investment, $\$10^6$	10 to 12	0.4
Total Annualized Cost, $\$10^6$	5.2	0.2
Annualized Unit Cost, \$/Mg	350	10.3
% Base Plant Capital Investment	1.3 to 1.6	0.05
% Base Plant Annualized Cost	2.8	0.1

Two secondary waste streams are generated by this process, namely, a flue gas stream and a residue stream. It is not possible to estimate the characteristics of the flue gas, but the cost for controlling this is included in the incinerator cost estimates presented in Table 4-75. The incinerator is assumed to be equipped with a scrubber for particulate control.

The flow rate of the residue stream is estimated to be 0.11 Mg/hr, assuming a 99.9% destruction of organics (see Section 4.2). The residue is expected to contain about 0.33% organics and other inert materials. Most of the trace metals originally present in the biosludge will be accumulated in the residue. Applicable treatment/disposal techniques include fixation/encapsulation and landfill.

4.3.4.2 Disposal

Biological treatment sludges may be disposed of in landfills, surface impoundment, or by land treatment. Landfill and surface impoundment have been discussed in the previous sections. The following is a brief description of land treatment of biosludge.

In land treatment, biological treatment sludge may or may not require dewatering prior to application to the land. Depending on the physical state, or the degree of dewatering performed, the sludges are transported to the land treatment site either by truck or hydraulic means. The sludges are spread with bulldozers, loaders, graders, or box spreaders. The site is generally subdivided into several plots which are treated in sequence. After waste application and evaporation of any associated water, the plot is plowed periodically until the waste has been decomposed. Chemicals such as nitrogen, phosphorus, and potassium may be added periodically as nutrients, and neutralizing agents (e.g., lime) may be added to maintain the proper pH level (7 to 9).

The estimated costs for land treating the biosludges are summarized in Table 4-75. The capital investment presented in Table 4-75 includes land preparation costs ($0.52/m^2), waste spreading equipment costs ($160,000), and monitoring well costs ($25,000). The annualized costs include the cost of labor, fuel, monitoring, maintenance, and amortized capital. No land or transportation costs are included. It is estimated that about 20,000 m^2 of land is required. Assuming a unit land cost of $5,000 per 10,000 m^2, this would increase the total capital investment by more than 25%. Depending on the distances involved, including transportation costs may more than double the annualized unit cost.

4.3.5 Spent Catalysts and Sulfur Guard

Four types of catalysts may potentially be used in a Lurgi-based plant. These materials eventually become deactivated and require decommissioning and disposal. Spent sulfur guard, which is not a catalyst, is also included in this discussion because 1) this is also a small volume, intermittent stream, and 2) applicable controls are similar. Table 4-76 summarizes the estimated average annual quantities of spent catalysts. It should be pointed out that although the flow rates are presented in Mg/yr, these streams only occur intermittently, about once every three to five years. Due to the proprietary nature of most catalysts, there is little information available on the reuse and disposal techniques applicable to specific catalysts. Because of this, spent catalyst reuse, treatment, and disposal are discussed in general terms in the following sections, with only brief mention of specific techniques applicable to individual catalysts.

TABLE 4-76. SUMMARY OF FLOW RATES FOR SPENT CATALYSTS AND SULFUR GUARD

Stream	Flow Rate, Mg/yr
Spent Shift Catalyst	40
Spent Sulfur Guard	250
Spent Methanation Catalyst	20
Spent Synthesis Catalyst	50-3500
Spent Claus Catalyst	7

4.3.5.1 Treatment

Spent catalysts may be chemically fixed or encapsulated before final disposal to prevent leaching of undesirable substances. When fixing these with cement-based techniques, the weight of the fixed material may be twice its original weight (80), i.e., a 1:1 chemical/spent catalyst ratio may be needed. As discussed before, the performance and cost for this alternative can only be established after thorough treatability studies.

4.3.5.2 Resource Recovery and Reuse

Spent catalysts may be reused after reactivation by a contractor or the original vendor. Also, the metal components of the catalyst may be recovered for other uses. The economics of the required regeneration processes and the market value of the metals will determine whether recovery and reuse are possible. In practice, return of the spent catalyst to the vendor for processing will likely be the approach of choice in many cases.

Because of the current tight cobalt supply and the high demand for this metal, it appears that the cobalt-based shift catalyst could be economically recovered. Increasing cobalt prices have fostered interest by catalyst manufacturers to develop improved methods to regenerate the catalyst, to recover the metal, and to search for other catalysts (mainly nickel-based) which can be used in place of the cobalt-based shift catalyst.

Regeneration of spent sulfur guard, Claus catalyst, Mobil M synthesis catalyst, and Fischer-Tropsch synthesis catalyst is expected to be economically unattractive because of the low market values of the base materials of these catalysts (zinc for sulfur guard, bauxite for Claus catalyst, zeolite for Mobil M synthesis catalyst, and iron for Fischer-Tropsch synthesis catalyst).

4.3.5.3 Disposal

Spent catalysts and sulfur guards may be chemically fixed or encapsulated before final disposal to minimize leaching of toxic substances or they may be disposed of once they are decommissioned. When disposed of, these materials are likely to be placed in landfills. The overall spent catalyst generation rate is largely dependent upon the synthesis process used in the plant. As discussed before, assuming these materials are disposed of in one common landfill with the other solid wastes from the plant, the annualized unit costs would be $2.7/Mg and $5.3/Mg, respectively, for a nonlined and lined landfill. The annualized disposal costs for these materials would range from $1,000 to $20,000, depending on the landfill design and the synthesis process used.

SECTION 5

DATA GAPS AND LIMITATIONS

Because of the inherent gaps and limitations which exist in the data base used to develop this manual, it is important for all users to understand the extent to which the performance and cost estimates presented here are supported by actual operating data, extrapolations from closely related applications, and/or engineering calculations/judgments. The purpose of this section is to convey a sense of the applicability and completeness of the data base used in the development of this manual.

Since no commercial Lurgi-based SNG or indirect liquefaction facility currently exists in the U.S., and since very limited data are publicly available for the only significant facility of this type outside the U.S. (SASOL, S.A.), background data for this manual could not be drawn exclusively from operating commercial facilities. Rather, considerable data were obtained from other commercial applications of Lurgi gasification and/or synthesis technologies, from applications of candidate controls in related industries, and from pilot- or bench-scale studies.

Since the early 1970s EPA has sponsored a significant environmental assessment program addressing synthetic fuels from coal technologies. This work has involved a combination of theoretical studies and plant data acquisition programs. These efforts have contributed both data and background knowledge used in the development of this manual. Table 5-1 lists the major data acquisition programs sponsored or cosponsored by the EPA which have provided background data used in the development of this PCTM. As indicated, the data encompass specific research projects, pilot-level sampling and analysis projects, and source sampling of foreign and domestic commercial production facilities.

TABLE 5-1. COMPLETED AND ONGOING DATA ACQUISITION PROGRAMS AT COAL GASIFICATION FACILITIES SPONSORED OR CO-SPONSORED BY THE EPA

Facility	Information Classification	Coal Used	Products
Medium/High Btu Gasification and Indirect Liquefaction Facilities (Foreign)			
• Lurgi or Lurgi-Type Gasification			
- Kosovo, Yugoslavia	Data acquisition	Lignite	Medium Btu gas
- SASOL, S.A.	Plant visit and discussions	Low rank bituminous	Various via indirect liquefaction
- Westfield, Scotland	Plant visit and discussions	Various	Test center
• Koppers-Totzek Gasification			
- Modderfontein, S.A.	Data acquisition	High vol. "B" bituminous	Ammonia
- Ptolemais, Greece	Data acquisition (TVA & EPA)	Bituminous	Ammonia
- Kutahya, Turkey	Plant visit and discussions	Lignite	Ammonia
• Winkler Gasification			
- Kutahya, Turkey	Plant visit and discussions	Lignite	Ammonia
• Texaco Gasification			
- Federal Republic of Germany	Data acquisition (EPRI, TVA, & EPA)	Ill. No. 6 bituminous	Test center
Low-Btu Gasification Facilities (U.S.)			
• Wellman Galusha			
- Site No. 1	Data acquisition	Anthracite	Fuel gas
- Site No. 2	Data acquisition	Lignite	Test center
• Chapman/Wilputte	Data acquisition	Low sulfur bituminous	Fuel gas
• Riley	Data acquisition	Lignite	Test center
• Stoic (Foster Wheeler)	Data acquisition (DOE & EPA)	Western bituminous	Fuel gas
Control Research Facilities			
• Raw/Acid Gas Cleanup (Fluidized Bed Gasifier)	North Carolina State University	Various	Test center
• Wastewater Treatability Studies	University of North Carolina	Various	Test center
• Pollutant Identification (Bench Scale Gasifier)	Research Triangle Institute	Various	Test center
• Ash Leaching Evaluations	University of Illinois	Various	Test center
Other Domestic Facilities			
• Texaco Gasification			
- Ammonia from coal plant, TVA	Data acquisition	Bituminous	Ammonia
• Rectisol Acid Gas Cleanup	Texaco, Wilmington, California	Oil partial oxidation	Process hydrogen

Section 5
Data Gaps/Limitations

Generally, estimates of the characteristics of uncontrolled waste streams were based upon available data from operating Lurgi-type facilities (SASOL, S. A. , Kosovo, Yugoslavia, and Westfield, Scotland). These data are believed to reasonably represent the waste streams which will be encountered in future U. S. Lurgi-based synthetic fuels facilities. However, the base plant waste stream characteristics are extrapolations from the referenced data sources and the accuracy of these extrapolations is dependent on the representativeness of the facility from which the test data were taken. The representativeness, in turn, is dependent on coal feedstock properties as well as the process design features and operating conditions.

Since very limited data on the performance of pollution control technologies are available from actual operating synthetic fuels plants, many assumptions were made to estimate the performance and cost of controls applied to Lurgi-based facilities. The majority of the available data have been obtained from: 1) bench- and pilot-scale evaluations of control technologies using waste streams from synthetic fuel processes, and 2) performance of controls on similar waste streams from related industries. This section summarizes the industry sources used and indicates the applicability of that information to Lurgi-based synfuels facilities. Some extrapolations of control technology performance and costs can be made with a relatively high degree of confidence (e.g., boiler flue gas controls). However, other extrapolations are based on unproven (although not necessarily incorrect) assumptions and engineering calculations/judgements.

Readers of this manual should use the information in this section to understand the extent and applicability of the data base supporting the waste stream characterization data presented in Section 3 and the pollution control performance and cost data presented in Section 4. As commercial synthetic fuel plants are built, the EPA will continue conducting research in order to develop a more comprehensive data base. In the interim, the Agency encourages facility planners, permit officials, and other interested parties to take advantage of, and interact with EPA to improve, the information contained in this document.

Tables 5-2 through 5-4 summarize (for gaseous, aqueous, and solid media, respectively) the major sources of data used to develop this manual and some gaps and limitations associated with that data. Table 5-5 presents similar types of information for the products and byproducts produced by the subject technologies of this PCTM. Waste streams are addressed first in Tables 5-2 through 5-4, followed by information on pollution controls for those waste streams. For each waste stream and pollution control the source of the data used in the manuals is identified by a "key" and the commercial development status of that source of information is noted. Reference is also made to Sections of the PCTM where additional data/discussion is presented.

Not all of the waste streams and control techniques addressed by this manual are included in Tables 5-2 through 5-4. The streams included are believed to be the major waste streams, in terms of waste volume and/or expected pollutant loadings, which are unique to Lurgi-based synfuels facilities. The controls included in the tables are examples of those that can be used to treat the major waste streams.

Some of the waste streams and applicable controls that are not listed in Tables 5-2 through 5-4 are those that have been well characterized or commercially proven in related industries. These streams/controls are considered nonunique to synthetic fuels facilities. For example the compositions of flue gases from coal-fired boilers are well defined, based on numerous evaluations of industrial and utility boilers. Similarly, the performance and cost of controls (such as flue gas desulfurization systems, ESPs, and baghouses) for boiler flue gases are also well defined. Other waste streams (and applicable controls) not discussed in Tables 5-2 to 5-4 include those from coal storage and handling operations and raw water treatment facilities.

A data gap or limitation which exists for essentially all pollution control technologies relates to reliability. Because most of the potentially applicable pollution control technologies have not been employed in Lurgi-based synthetic fuels facilities, few directly related reliability data are available. Further, the overall characteristics and variability of waste streams in coal conversion facilities are often sufficiently different from those encountered in other industries so that it is not certain whether reliability data accumulated in other industries will be applicable to coal conversion processes. These are particularly significant considerations with respect to wastewater treatment technologies and, to a lesser extent, hold for gaseous and solid waste control technologies also. It should be noted, however, that such data gaps cannot be addressed for specific controls prior to the application of these controls to coal conversion waste streams.

Research needs aimed at filling the identified data gaps for specific waste streams and pollution controls are also presented in Tables 5-2 through 5-4. These research needs include studies that can be implemented:

- At the bench- and pilot-scale,
- At currently operating gasification facilities in foreign countries, and
- By monitoring the performance of U.S. synfuels facilities after startup.

In general, these additional data needs fall into one of three categories:

- Data required by facility owners either to evaluate the potential applicability of a pollution control process or to design the processes selected for use. This type of data is generally obtained through bench- , pilot-, and commercial-scale testing as part of project feasibility studies and engineering design activities.

- Data that would contribute to a better general understanding of
  1) the characteristics of uncontrolled waste streams and the dependence of those characteristics on the type of coal gasified, the design of a facility, and its operating characteristics, and
  2) the performance, reliability, capital investment requirements, and operating costs of pollution controls.

- Data relating to the characteristics and hence potential control needs for secondary waste streams produced by pollution controls.

TABLE 5-2. DATA GAPS AND RESEARCH NEEDS - GASEOUS MEDIUM

Keys for Data Sources

Technology Status Keys

A1	Commercial or demonstration-scale application in a Lurgi or Lurgi-type gasification facility
A2	Commercial or demonstration-scale application on an "identical" stream in a related industry
A3	Commercial or demonstration-scale application of a similar stream in a non-Lurgi gasification facility
B	Bench- or pilot-scale testing
C	Technology transfer from another industry - similar but not identical streams
D	Conceptual

Data Sources/Location

1.	Kosovo, Yugoslavia Lurgi-type facility
2.	Sasol, S.A.
3.	Trials of American coals at Westfield, Scotland
4.	Chapel Hill, N.C. (UNC) - synfuels wastewater treatability test facility
5.	Technology transfer from related industries
5A.	Petroleum refining/petrochemical production
5B.	Coke production
5C.	Electric power production
5D.	Natural gas processing
5E.	Municipal gas processing
6.	Conceptual or proposed designs/engineering studies
7.	Vendor supplied information

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Waste Streams		
Rectisol Acid Gases		
Available data have been obtained from commercial scale facilities. Sulfur and nitrogen components of acid gases are based primarily upon data from the Kosovo, Yugoslavia gasification facility. Hydrocarbon concentrations are based upon data from ANR for test gasification of North Dakota lignite at Sasol, S.A. Status: A1, A3 Data Sources: 1, 2, 3, 6, 7 PCTM Reference: Sections 3.3.3, 4.1.1	Uncertainties in acid gas compositions relate primarily to uncertainties in the raw Lurgi gas composition. The specific design of a Rectisol unit will depend on the raw gas quality, the clean synthesis gas purity requirements, and atmospheric emission constraints. In addition, Rectisol unit design can be impacted if a facility requires the generation of a CO_2-rich offgas for sale or reuse. Therefore, the design of a Rectisol unit is a very complex site-specific issue and acid gas composition will vary from site-to-site. In particular, the mercaptan and organic levels in the acid gas have not been established. Kosovo data are not consistent with data from GPA, Sasol, or Westfield. It is not known whether the mercaptan and organic compositions are functions of coal type and/or gasification operating conditions.	Sulfur and organic species in Lurgi product gas need to be determined for specific coals and gasifier designs in the U.S. Source testing at the first U.S. Lurgi plants offers the best opportunity for obtaining data.

(Continued)

TABLE 5-2. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Coal Lockhopper Gases and Transient Waste Gases		
Characterization is based on data from Kosovo, Yugoslavia facility and from Lurgi product gas composition data from Sasol, Westfield, and the Great Plains project. Status: A1 Data Sources: 1, 2, 3, 6 PCTM Reference: Sections 3.2.4, 4.1.2	The levels of coal dust and tar aerosols found in the low-pressure coal lockhopper vent gas were based on data taken at Kosovo. Design features and operating procedures may be different at facilities built in the U.S. No experience is reported in publicly available literature on the operability and performance of air ejected lockhoppers. Uncertainties with high-pressure lock gas and transients relate primarily to operability of controls. Compositions are only approximately known; however, uncertainties do not influence choice or design of controls.	Data on the dust and tar levels in air ejected lock gases may be obtained at Sasol, S.A. and at the first U.S. facilities which become operational. Additional data from older Lurgi facilities or pilot gasification facilities are not likely to provide further insight.
Control Technologies		
Nonselective Rectisol		
Operating data from Sasol and designs for Great Plains serve as the main data base. Secondary Waste Streams: H_2S-lean offgases, Methanol/water still bottoms Status: A1 Data Sources: 2, 6, 7 PCTM Reference: Sections 3.3.3, 4.1.8.2	Data gaps relate primarily to feed composition rather than performance of nonselective Rectisol. There is some question as to the distribution of low molecular weight mercaptans between the naphtha and acid gases.	No additional research needs are identified. Uncertainties do not affect choice or design of controls for nonselective Rectisol acid gases. Nonselective acid gas removal is essentially a process step and not pollution control.
Selective Rectisol		
Operating data was derived for Lurgi gasification from a partially selective unit at Kosovo, Yugoslavia. Additional information was obtained from design for Wesco Lurgi facility and highly selective units operating in entrained gasification applications. Secondary Waste Streams: H_2S-rich offgases, CO_2-rich offgases, Methanol/water still bottoms Status: A1 Data Sources: 1, 5A, 6, 7 PCTM Reference: Sections 3.3.3, 4.1.1, 4.1.8.1	As noted above, feed composition presents some uncertainties. Data gaps also relate to selectivity obtainable as a function of cost and energy requirements. The extent to which organics and CO can be excluded from either bulk H_2S rich or CO_2 rich fractions is unclear.	Licensors are believed to have most of the needed data. Since selective Rectisol can serve both process and pollution control functions, source testing at the first U.S. facilities would verify emissions levels reported to be achievable by the vendors.

(Continued)

TABLE 5-2. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Amine Systems		
Operating data are from refinery, coke plant, and natural gas applications. Amine processes could have major applications in Lurgi facilities for removing organics from Claus feeds. H_2S enrichment is also obtained with amine units. Secondary Waste Streams: Amine solution degradation products (can be either aqueous blowdown or filtered solids) Status: A2, C Data Sources: 5A, 5D, 6, 7 PCTM Reference: Sections 4.1.1, 4.1.8.1	Publicly available operating data for selective amine systems (e.g., MDEA or TEA) are limited. The fate of minor components (COS, HCN, and NH_3) in these processes is not well known nor is the degree of H_2S enrichment attainable in high CO_2 applications. Accurate costs related to such selectivity are not publicly available.	Licensors are believed to have most of the data indicated. Some of these may be obtainable from the vendors. Amine systems can serve a pollution control function in Lurgi applications; hence, source testing of the first U.S. facilities could verify design data.
Claus		
Operating data are from applications in coke plants, oil refineries, and gas processing plants. Secondary Waste Streams: Knockout drum condensate, Spent catalyst, Catalyst regeneration offgas Source: A2, C Data Sources: 5A, 5B, 5D, 7 PCTM Reference: Sections 4.1.1, 4.1.8.1	Existing facilities provide data covering many of the constituents expected in coal gasification. Uncertainties relate to minimum levels of H_2S processable by the straight through mode. With Lurgi acid gases, organics may preclude split flow mode. Use of oxygen or enriched air offers advantages, but operating data from existing facilities are not currently available. There is limited data on the maximum allowable concentration of contaminants such as heavier organics and HCN. The effect of feed fluctuations on tail gas composition is not well established. No data are available on characteristics and generation rate of spent catalyst.	The practical limits for straight through operation in high CO_2 applications need definition. Existing facilities may provide some of these data. Operating experience for oxygen-fired units may also be obtainable from vendors or plant operators. Source testing at the first U.S. facilities can provide data base for effects of feed concentration and fluctuations on tail gas composition and unit performance. Spent catalyst characteristics are not likely to affect disposal options, so that additional data may not be needed.

(Continued)

TABLE 5-2. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Stretford		
Operating data are primarily from non-gasification applications with low CO_2 levels. Limited information available for the only existing unit in Lurgi gasification service. Secondary Waste Streams: Stretford solution purge stream, Oxidizer vent gas Status: A1, A3 Data Source: 2, 5A, 5D, 6, 7 PCTM Reference: Sections 4.1.1, 4.1.8.2	Uncertainties relate mainly to the operability of units in high CO_2 applications. There is also some question as to the fate of low molecular weight mercaptans and ammonia in Stretford systems. The reductive incineration system for blowdown has not been demonstrated in commercial applications. Stretford costs as a function of both volumetric flow and sulfur loading are not accurately known. Characterization data and treatment scheme for solution purge stream are needed. Oxidizer vent gas characterization data is limited.	Data could be obtained on the operating experience at Sasol, and on the modification to processes recently made there using a new (proprietary) solvent. Source testing at the first U.S. facilities can establish a data base for performance in high CO_2 applications, as well as defining the amounts of non-H_2S sulfur present in Lurgi acid gases. Work is currently being done to develop techniques to handle the Stretford solution purge stream. Purge stream characterization data from a commercial synfuels Stretford unit is desired.
Wellman-Lord (W-L)		
Operating data are for refinery and power plant applications. Secondary Waste Streams: Thiosulfate/sulfate purge Status: C, D Data Sources: 5A, 5C, 6, 7 PCTM Reference: Sections 4.1.1, 4.1.8.1	Since W-L feed is incinerated, and since the absorbing solution is not affected by CO_2, data from existing units should be directly applicable to Lurgi service. Uncertainties relate to costs as a function of sulfur loading and volumetric flow.	Data are needed on costs for W-L relative to SCOT or BEAVON systems with similar design performances.
Incineration		
Emissions data are available for commercial scale incineration and/or combustion of a number of different types of waste gases and liquids. Secondary Waste Streams: None Status: C Data Sources: 5A, 5B, 5C, 5D PCTM Reference: Sections 4.1.1, 4.1.2, 4.1.3, 4.1.8	Uncertainties relate primarily to the operability of and emissions from incinerators with feed gases having high CO_2 levels and low heating values. Operability is also a question for intermittent and transient waste gases.	Data on the emissions of incinerators in similar applications would provide some basis for assessing performance with Lurgi gases. The VOC, POM, and HCN levels from combustion of Lurgi byproducts as fuels are also of interest.

(Continued)

TABLE 5-2. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Beavon/Stretford (also see previous Stretford discussion)		
Available data have been obtained for Claus plant tail gas feeds in refinery service with low CO_2. Secondary Waste Streams: Sour water condensate from the Beavon reactor effluent, Spent catalyst from the Beavon reactor, Stretford secondary streams listed in previous discussion Status: C, D Data Sources: 5A, 6, 7 PCTM References: Sections 4.1.1, 4.1.8.1	Uncertainties relate to performance of the catalytic section in high CO_2 service. Also, the effect of the catalyst on mercaptans is unknown. Other data gaps and limitations are discussed in connection with Stretford. Characteristics and/or generation rates of spent catalyst and condensate are not well known.	No Beavon units are currently treating Lurgi type gases and no proposed Lurgi facilities feature Beavon to date. If Beavon units are used in Lurgi facilities, source testing can establish performance in high CO_2 applications. Additional data on characteristics of spent catalyst and condensate would be useful for defining control needs.
SCOT		
Available data have been obtained for both conventional refinery (low CO_2) applications and oil gasification and natural gas service (where high CO_2 levels are encountered). Secondary Waste Streams: Sour water from the quench tower, Spent catalyst Status: C, D Data Sources: 5A, 5D, 6, 7 PCTM Reference: Sections 4.1.1, 4.1.8.1	Catalytic section of SCOT is similar to that of Beavon, and hence uncertainties in Lurgi service are similar. Also, uncertainties in amine section have been identified previously. Costs related to both sulfur loading and volumetric flow are not accurately known. Characteristics and/or generation rates of spent catalyst and condensate are not well known.	Several existing SCOT facilities treat gases similar to those expected in Lurgi service. The performance of both the catalytic and amine sections of these units could be tested. Such facilities do not, however, handle mercaptans in the feed gas. Additional data on characteristics of spent catalyst and condensates would be useful to define control needs.
Flares		
Data used in this manual are based on experience in the petrochemical and refining industries Secondary Waste Streams: None Status: C Data Sources: 5A PCTM Reference: Section 4.1.1	Performance data for flares on synfuels gaseous stream containing combustible species such as VOC, CO, H_2S does not exist in the public domain.	Adequate methods are not available for characterizing flared gas composition. If methods are developed, it would be beneficial to characterize inlet and flared gases as a function of flow rate and flare conditions. Until adequate methods are developed, characterization of flare feed streams is desirable.

TABLE 5-3. DATA GAPS AND RESEARCH NEEDS - AQUEOUS MEDIUM

Keys for Data Sources

Technology Status Keys:

A1 Commercial or demonstration-scale application in a Lurgi or Lurgi-type gasification facility

A2 Commercial or demonstration-scale application on an "identical" stream in a related industry

A3 Commercial or demonstration-scale application of a similar stream in a non-Lurgi gasification facility

B Bench- or pilot-scale testing

C Technology transfer from another industry - similar but not identical streams

D Conceptual

Data Sources/Location Keys:

1. Kosovo, Yugoslavia Lurgi-type facility
2. Sasol, S.A.
3. Trials of American coals at Westfield, Scotland
4. Chapel Hill, N.C. (UNC) - synfuels wastewater treatability test facility
5. Technology transfer from related industries
5A. Petroleum refining/petrochemical production
5B. Coke production
5C. Electric power production
5D. Natural gas processing
5E. Municipal gas processing
6. Conceptual or proposed designs/engineering studies
7. Vendor supplied information

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Wastewater Streams		
Gas Liquor (wastewater from tar/oil separation)		
Gas liquor contains a variety of organic and inorganic (mainly dissolved gases) constituents, many of which are present in high concentrations. Although the presence of these components is not highly dependent on the coal gasified or the gasifier operating conditions, the concentrations of these components are. Data on gas liquor are based on analyses from Lurgi-type plants gasifying North Dakota lignite, Yugoslavian lignite, Rosebud subbituminous coal, and Illinois No. 6 and No. 5 and Pittsburgh No. 8 bituminous coals. Status: A1 Data Sources: 1, 2, 3 PCTM Reference: Section 3.3.5	A complete characterization of gas liquor including all water quality parameters, organic speciation, and trace elements is not currently publicly-available for any coal type or plant. Where data gaps existed, engineering judgement was used to develop correlations with data from other coal types in this study. Due to differences in system configurations, test objectives, sample collection/handling techniques, and waste stream blending and analytical procedures, the analyses are not well defined in the literature. Some of the analyses performed were on "aged" samples rather than "fresh" samples. It is, therefore, difficult to extrapolate these data to other coal types or plants.	Data on the concentrations of specific organic and inorganic species and their dependence on coal type and gasifier operating conditions is desirable in order to adequately evaluate treatment, reuse, and/or disposal alternatives. This information is especially important in the evaluation, selection, and design of treatment processes following bulk organics and dissolved gases removal. This kind of data is believed to exist, but to date has largely been developed and held as part of proprietary plant design data bases. The first U.S. Lurgi plants offer the best opportunities for source testing. Data may also be obtained from SASOL.

(Continued)

TABLE 5-3. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Rectisol Methanol/Water Still Bottoms		
Wastewater from the Rectisol unit contains dissolved gases such as ammonia and cyanides as well as some dissolved organics and traces of methanol. Data on the composition of this stream were obtained from Lurgi-based plants in South Africa. Status: A1 Data Sources: 1, 2 PCTM Reference: Section 3.3.5	Only limited data are available on the composition of this stream and on the factors which influence its composition and flow rate. However, the types of pollutants expected to be present can be estimated from the composition of the Rectisol feed gas.	Most pollutants contained in this stream are also present in gas liquors and this stream will most likely be combined with gas liquor for treatment. Since its flow rate is very small (compared to the gas liquor flow) and its pollutant loadings are low, the available qualitative and semi-quantitative characterization data are expected to be adequate to determine its impact on the treatment system for raw gas liquor.
Synthesis Wastewaters		
Wastewaters from the Fischer-Tropsch, Methanol, and Mobil M-gasoline synthesis processes contain dissolved organics, but negligible amounts of inorganics. Data on the compositions and flow rates of these wastewaters were obtained from engineering studies of the subject technologies. SNG synthesis condensate are expected to contain neglible levels of pollutants. Status: D Data Source: 6 PCTM Reference: Section 3.4.3	No analysis of actual streams have been published to date. These wastewaters are expected to be similar to those produced by certain petroleum and petrochemical industry processes.	Data on the composition of these streams is desired in order to adequately design control systems to properly allow for the combination of these wastes (with the probable exception of SNG synthesis condensate) with gas liquor for treatment in common equipment.
Control Technologies		
Bulk Organics Removal		
Phenosolvan		
The Phenosolvan process is currently used in all operating Lurgi-based synfuels facilities and is generally considered a part of the proprietary Lurgi-design package. Performance data were obtained from engineering studies. Secondary waste streams: Filter Backwash, Spent Filter Medium Status: A1, D Data Source: 6 PCTM References: Sections 4.2.1.2, 4.2.2.1	Only very limited species-specific performance data are available. In addition, different solvents can be used and performance is dependent on the solvent used. Data on residual quantities of solvent remaining with treated wastewater are limited.	Determine the presence and concentration of organic and inorganic pollutants in treated wastewater that could adversely impact downstream treatment units. Investigate the use of alternative or multiple solvents to enhance performance or effect removal of components which cause operating problems in downstream equipment. (This is currently being investigated by DOE). Quantify residual solvent levels in treated wastewaters - determine if these levels have adverse impacts on downstream treatment processes.

(Continued)

TABLE 5-3. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Dissolved Gases Removal		
PHOSAM-W		
The PHOSAM-W process has been commercially proven on coke oven wastewaters which are comparable to gas liquor. PHOSAM-W is proposed for use in several Lurgi-based plants. Secondary Waste Streams: Stripper offgases Status: C, D Data Sources: 5A, 6 PCTM References: Sections 4.2.1.3, 4.2.2.1	The impacts of dissolved organics on system operations are not well-known. Economically achievable performance on wastewaters containing high carbon dioxide and ammonia levels is not well documented, nor is the impact that complexes have on performance. No data are available on the levels of organic contaminants which may be present in the recovered ammonia and stripped acid gas streams.	Obtain data on the impacts that high molecular weight organics have on performance and the types and levels of organics which are (might be) present in the ammonia byproduct and stripped acid gas streams. Determine levels of residual ammonia, hydrogen sulfide, cyanides, and thiocyanates obtainable under economically viable operating conditions. Identify pretreatment steps which could enhance system performance.
Dissolved Organics Removal		
Biological Oxidation		
This technology has been commercially proven on similar wastewaters in the byproduct coking industry. Feasibility of this technology has been demonstrated for coal gasification wastewaters on the bench-scale. Biological oxidation has been proposed for use in most Lurgi-based synfuels plants and is currently used to treat dephenolized and stripped gas liquor at SASOL, although performance data are not publicly available. Secondary Waste Streams: Biological solids, offgases Status: B, C, D Data Sources: 4, 5B, 6 PCTM References: Sections 4.2.1.4, 4.2.2.1	Pollutant removal efficiencies and effluent qualities obtained from bench-scale studies are reasonably representative of what is achievable with full-scale plants but not necessarily what is maintainable on a long-term continuous basis. Relationships between the removal of inorganic nitrogen species (e.g., ammonia, cyanide, and thiocyanate) have not been defined (e.g., compounds preferentially removed, toxic effects, removal efficiencies). The current bench-scale treatability studies designed to optimize performance (e.g., BOD, TOC, COD removal) have been conducted primarily using single stage biological systems. Many synfuels applications may require multistage biological treatment to achieve an acceptable effluent for recycle or disposal. The data on multiple stage biological treatment is limited at this time. The fate of trace elements in the wastewaters are not well defined. Data identifying organics in untreated and treated wastewaters (e.g., priority pollutants, POMs, or other toxic materials) is also limited at this time.	Treatability studies on a pilot- and full-scale are needed to develop functional relationships between coal type, influent wastewater characteristics, and effluent quality. Opportunities may exist to obtain data on the SASOL II and III biological oxidation systems. Bench- or pilot-scale studies to optimize performance and effluent quality of single and multi-stage treatment schemes are needed. These studies can also address the removal mechanisms of nitrogen species and trace elements. Residual organics in treated wastewaters from bench-, pilot-, or full-scale facilities should be characterized. Treatability studies are needed to determine enhanced performance achievable with addition of powdered activated carbon to a biological system. Definition of gaseous emissions from aeration processes on a bench-, pilot-, and full-scale system is needed.

(Continued)

TABLE 5-3. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Biological Oxidation (Continued)	The effect of using powdered activated carbon with activated sludge on Lurgi wastewaters is not well known. No data are available on the potential gaseous emissions from aeration processes. Data characterizing biological solids is limited. Thus, evaluation of disposal options for these solids is also quite limited and generic.	Characterization of biological solids and evaluation of disposal and recycle options are needed. The potential production of unsettleable, fine, suspended solids should be investigated.
Residual Organics Removal		
Activated Carbon Adsorption Pollutant removal efficiencies are based primarily on data from the refining and byproduct coking industries. Expected reliability, capital, operating, and maintenance costs are also based on data from applications in the refining and byproduct coking industries. Secondary Waste Streams: Regeneration offgases, spent carbon fines Status: C, D Data Sources: 5A, 5B, 6 PCTM References: Sections 4.2.1.5, 4.2.2.1	Actual removal efficiencies will be dependent on pH, molecular size, and structure of the organics present in the wastewater. Limited data are available on the specific species present in Lurgi wastewaters which contribute to BOD, COD, and TOC loadings. As a result, performance of carbon adsorption on BOD, COD, and TOC has not been determined for these wastewaters. The removal efficiency and fate of trace elements are not well known. Effects of the variation of flow and composition on costs and reliability are not known. The leaching characteristics of spent carbon fines and ash from regeneration and quenching operations are not well defined. The presence and/or concentrations of organics in regenerator offgases is not known.	Laboratory- and pilot-scale performance tests on synfuels wastewaters are needed to verify design data, e.g., required contact times to obtain desired pollutant removals. These tests should encompass the range of influent strengths expected. Carbon adsorption performance evaluations or other tests are needed to determine pretreatment requirements and/or performance tradeoffs. Tests objectives should include determining the need for pH adjustment to enhance performance, optimizing the wastewater treatment temperature, and determining whether biocide addition is required to inhibit fouling from biological growth. Evaluate the leaching characteristics of spent carbon fines and ash from regeneration/quenching operations in pilot facilities or byproduct coking plants. Define final disposal and recycle alternatives. Determine the fate of removed organics and inorganics in the regeneration process.

(Continued)

TABLE 5-3. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Thermal Oxidation (Incineration)		
Thermal oxidation is widely used to destroy organics in a variety of industrial wastes. The application of this technology to Lurgi waste streams has been proposed in a number of synfuels plants.	The operating temperature and combustion zone residence time required to obtain a desired level of organics destruction is dependent on specific organics present.	Commercial scale facility monitoring should be implemented to confirm design basis and emission characteristics. Pilot studies could be implemented to provide additional data on wastewaters with varying compositions.
Secondary Waste Streams: Incinerator offgas	The materials of construction required to handle concentrated brines are not well defined.	
Status: C, D Data Source: 6 PCTM References: Sections 4.2.1.5, 4.2.2.1	Control needs for incinerator off-gases are not well-defined, nor are materials of construction requirements.	
Cooling Tower Oxidation/Concentration		
The use of treated wastewaters as cooling tower makeup is commercially proven in the petroleum refining industry as a means of reducing organic contaminants.	Degree of organics removal is not well known nor is the fate of removed organics.	Pilot- or full-scale tests should be conducted to determine the fate of organics and inorganics entering with the treated wastewater. Tests should determine the extent of biological oxidation, chemical oxidation, and air stripping. The first U.S. Lurgi plants offer the best opportunity to obtain the needed data.
Secondary Waste Streams: Cooling tower evaporation and drift, cooling system sludges	Potential operating problems may be caused by biological fouling and inorganic scale on heat exchange surfaces.	
Status: C	Organics in wastewater may limit effectiveness of conventional cooling system biocides or scale/corrosion inhibitors.	Tests should be conducted to determine the impact increased biological activity has on cooling system equipment performance and on treatment chemical requirements.
Data Source: 5A PCTM References: Sections 4.2.1.5, 4.2.2.1	Gaseous emissions due to air stripping of volatile components are not well defined. Organics present in drift could cause increased particulate emissions. Trace element concentrations in the drift have not been characterized.	Tests should be conducted to determine if corrosion problems will be increased and, if so, what corrective measures can be taken.

(Continued)

TABLE 5-3. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Dissolved Inorganics Removal		
Chemical Precipitation		
Chemical precipitation is a proven process for reducing alkalinity and hardness in raw waters and wastewaters. Process will also remove trace elements, depending on initial concentrations, inlet water composition, and system design. The technique has not been commercially demonstrated on coal gasification wastewaters. Secondary Waste Streams: Precipitated solids Status: C, D Data Sources: 5A, 5C, 6 PCTM References: Sections 4.2.1.6, 4.2.2.1	The performance of chemical precipitation in reducing alkalinity and hardness can be determined if the influent water chemistry is known. The performance in reducing trace metals is not well known and in any case is highly wastewater specific. The impact of organic constituents on system performance is not well defined. The composition of the precipitated solids is not well defined due to the unknown quantities of trace elements removed and possible organic contamination.	Conduct laboratory- or bench-scale tests to determine impact of residual organics on system performance and to determine achievable residual levels of trace elements. Conduct leachability/waste management studies to identify appropriate disposal methods for precipitated solids.
Wastewater Concentration		
Cooling Tower Oxidation/Concentration	Discussed previously under Residual Organics Removal	
Forced Evaporation		
Forced evaporation is commercially proven in wastewater applications in the steam electric utility industry and in various chemical manufacturing operations. Water recoveries of greater than 90 percent are reported. Several proposed synfuel facilities have incorporated forced evaporation in their wastewater treatment system design. Secondary Waste Streams: Noncondensible offgases, Recovered water Status: C Data Sources: 5A, 5C, 6 PCTM References: Sections 4.2.1.7, 4.2.2.1	The impact of residual organics and non-condensible gases on system operability and degree of water recovery obtainable is not well defined. Recovered water could be contaminated with vaporized organics and volatile gases as well as with entrained water. Costs for treating recovered water to make it suitable for reuse are highly site-specific and not well defined.	Conduct pilot- and commercial-scale tests on actual wastewaters to determine impact of noncondensible gases and organics on system operation and identify degree of contamination of recovered water. The first U.S. Lurgi plants offer an opportunity to obtain data. Conduct leachability/waste management studies to determine appropriate disposal methods for concentrated brine.

(Continued)

TABLE 5-3. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Residual Disposal		
Deep Well Injection		
Deep well injection is commercially proven on similar waste streams in oil production and industrial chemical applications and is proposed for use in synfuels plants. Acceptable practices are defined by conditions which are very site-specific (i.e., subsurface geological and hydrological considerations). Status: C, D Data Sources: 5A, 6 PCTM References: Sections 4.2.1.8, 4.2.2.1	Design of deep well injection system is very site dependent. Major concerns are pretreatment requirements for wastes being injected. Acceptable levels of organics and inorganics are not well documented. Inorganics scaling and biological activity under down-hole conditions must be avoided. Pretreatment requirement could include organics destruction or removal, reduction in selected inorganics to avoid scaling, and/or pH adjustment.	Because of the site- and waste-specific nature of deep well injection, generalized research will be of limited value. On-site test wells (at a commercial facility) using actual wastewaters or wastewaters with simulated characteristics of the actual wastes to be disposed can provide the best insight to reliable disposal well operation.
Surface Impoundment		
Surface impoundment is commercially proven on similar waste streams in minerals extraction, petroleum refining, and steam electric utility operations in the western U.S. It is proposed for use in some synfuels plants. Use of this technique is dependent upon the location having a high net annual evporation rate and land availability. Secondary Waste Streams: Offgases from pond surface, Water leakage from containment Status: C Data Sources: 5A, 5C PCTM References: Sections 4.2.1.8, 4.2.2.1	No data are available on the composition or quantity of off-gases from the impoundment. Biological activity in the pond could generate hydrogen sulfide, ammonia, and organics. No data are available on the long-term integrity of the containment pond.	Economic methods to detect and control pond leakage need to be identified. Test programs should be conducted to quantify air emissions from ponds in order to determine if environmental concerns exist. Correlations between air emissions and influent wastewater composition would be useful.

TABLE 5-4. DATA GAPS AND RESEARCH NEEDS - SOLID WASTES

Keys for Data Sources

Technology Status Keys

A1	Commercial or demonstration-scale application in a Lurgi or Lurgi-type gasification facility
A2	Commercial or demonstration-scale application on an "identical" stream in a related industry
A3	Commercial or demonstration-scale application of a similar stream in a non-Lurgi gasification facility
B	Bench- or pilot-scale testing
C	Technology transfer from another industry - similar but not identical streams
D	Conceptual

Data Sources/Location

1.	Kosovo, Yugoslavia Lurgi-type facility
2.	Sasol, S.A.
3.	Trials of American coals at Westfield, Scotland
4.	Chapel Hill, N.C. (UNC) - synfuels wastewater treatability test facility
5.	Technology transfer from related industries
5A.	Petroleum refining/petrochemical production
5B.	Coke production
5C.	Electric power production
5D.	Natural gas processing
5E.	Municipal gas processing
6.	Conceptual or proposed designs/engineering studies
7.	Vendor supplied information

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Waste Streams		
Lurgi Gasifier Ash		
The ash leachability data are based upon tests conducted on unquenched ashes obtained from commercial scale gasification of Illinois No. 6, Montana Rosebud, and Dunn County, ND, coals. Status: A1 Data Sources: 1, 2, 3 PCTM References: Sections 4.3.1, 4.3.2.1	Long term leachability data are not available for quenched ashes. There is some uncertainty regarding sulfur oxidation and consequent acid generation in ash. Trace metals may become leachable under acidic conditions.	Long term column or landfill cell leaching studies should be performed to determine the long term ash leachate characteristics. Appropriate materials for these studies may not be available until the first Lurgi plant is built in the U.S. The effect of quench water quality on quenched ash leachate should be evaluated.
Control Technologies		
Resource Recovery		
Potential alternatives for recycling the gasifier ash are based upon current practices for coal-fired power plant boiler ashes. Status: A2 Data Sources: 5C PCTM Reference: Sections 4.3.1.1, 4.3.2.1	Available market for recycling the ash is uncertain.	The availability of market is highly dependent upon local conditions which can only be assessed on a site-by-site basis.

(Continued)

TABLE 5-4. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Landfill		
Disposal of the ash in landfills is based upon current practices in the utility and other industries. Secondary Waste Streams: Atmospheric emissions, Leachate Status: A2 Data Sources: 5B, 5C PCTM Reference: Sections 4.3.1.4, 4.3.2.1	The long term leachate generation rates and characteristics are not known; the compatibility and long term performance of landfill liners have not been established.	Long term column or landfill cell studies are needed to characterize the leachate, to determine the performance of the liners, and to assess the attenuation value of various substrate materials (soils) for metals in leachates.
Surface Impoundments		
Disposal of the ash in surface impoundments are based upon current practices in the utility and other industries. Secondary Waste Stream: Leachate Status: A2 Data Sources: 5B, 5C PCTM Reference: Sections 4.3.1.5, 4.3.2.1	The long term leachate generation rates and characateristics are not known; the compatibility and long term performance of liners have not been established.	Long term column or cell studies are needed to characterize the leachate, to determine the performance of the liners, and to assess the attenuation value of various substrate materials (soils) for metals in leachates.

TABLE 5-5. DATA GAPS AND RESEARCH NEEDS - PRODUCTS AND BYPRODUCTS

Keys for Data Sources

Technology Status Keys

A1	Commercial or demonstration-scale application in a Lurgi or Lurgi-type gasification facility
A2	Commercial or demonstration-scale application on an "identical" stream in a related industry
A3	Commercial or demonstration-scale application of a similar stream in a non-Lurgi gasification facility
B	Bench- or pilot-scale testing
C	Technology transfer from another industry - similar but not identical streams
D	Conceptual

Data Sources/Location

1.	Kosovo, Yugoslavia Lurgi-type facility
2.	Sasol, S.A.
3.	Trials of American coals at Westfield, Scotland
4.	Chapel Hill, N.C. (UNC) - synfuels wastewater treatability test facility
5.	Technology transfer from related industries
5A.	Petroleum refining/petrochemical production
5B.	Coke production
5C.	Electric power production
5D.	Natural gas processing
5E.	Municipal gas processing
6.	Conceptual or proposed designs/engineering studies
7.	Vendor supplied information

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Products		
SNG (both product and coproduct) and LPG (from Fischer-Tropsch and Mobil M synthesis)		
Production rates and composition estimates are based on conceptual/proposed design information. Status: D Data Sources: 6 PCTM Reference: Sections 3.5.4, 3.5.5	Data from a commercial facility are not available, especially concerning possible minor and trace components.	The composition of SNG should be determined after startup of the first commercial Lurgi SNG plant. Characterization data on LPG from Fischer-Tropsch may be obtainable from SASOL.
Gasoline, heavy fuel oil, diesel oil, mixed alcohols (F-T synthesis), and gasoline (Mobil M synthesis)		
Production rates and composition estimates are based on conceptual design information. Status: D Data Source: 6 PCTM Reference: Sections 3.5.2, 3.5.3	Characterization and storage stability data are not available to determine the compatibility of these products with their petroleum-derived counterparts.	Detailed characterization data are desired. Environmental effects associated with fugitive and evaporative emissions should be determined. Potential effects need to be compared with those for analog petroleum products. Data on Fischer-Tropsch products may be obtainable from SASOL.

(Continued)

TABLE 5-5. (Continued)

Stream or Control Technology	Data Gaps and Limitations	Research Needs
Fuel grade methanol (methanol synthesis)		
Production rates and composition estimates are based on conceptual design information. Status: 6 Data Source: D PCTM Reference: Section 3.5.1	Characterization data for methanol from indirect coal liquefaction facilities are limited. The influence of synthesis process variables on product methanol characteristics is unknown.	Data on the minor and trace components in coal-derived methanol is desired. Comparisons to non-coal-derived methanol should be made to determine if any special precautions in handling and use are appropriate.
Byproducts		
Lurgi tars, oils, phenols, and naphtha		
Production rates and composition estimates based on test data from commercial Lurgi and Lurgi-type gasification facilities. Status: A1 Data Source: 1, 2, 3	Characterization data, production rates, and storage stability data are limited. Presence of toxic components is expected, but detailed analyses are limited. Ability to upgrade for blending with other facility liquid fuel products is not well known.	Chemical and biological characterization data are desired if these byproducts are to be introduced into commercial trade. If byproducts are to be upgraded for blending with other products, chemical and physical property data are necesary to adequately design upgrading facilities.
PCTM Reference: Section 3.5.6	Flue gas emissions resulting from combustion of byproducts are limited (e.g., NO_x and organics).	Byproducts from commercial facilities should be evaluated as boiler fuel. Emissions should be characterized.
Ammonia and elemental sulfur		
Production rate estimates based on material flow calculations, engineering evaluations, and vendor data Status: A2, C, D Data Sources: 5A, 5B, 5D, 6, 7 PCTM Reference: Section 3.5.7	Data are lacking on the possible contaminants (and level of contamination) for both of these products.	Characterization data are desired in order to modify byproduct recovery process(es) or to design add-on purification process(es) in order to obtain a saleable byproduct. The first U.S. Lurgi plants constructed offer the best opportunity to acquire the data. Data may also be obtainable from SASOL and other foreign Lurgi-based facilities.

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APPENDIX A

LURGI DRY ASH COAL GASIFICATION

APPENDIX A

LURGI DRY ASH COAL GASIFICATION

Coal has been gasified commercially using the Lurgi dry ash process since before 1940. Continued development of the process, based on operational experience with a variety of coals, has resulted in the current system which can successfully process most varieties of coal including caking coals, lignite, and peat. Significant improvement has also been made in the quantity of coal which can be processed by a single gasifier (1).

Currently there are about 20 commercial installations of the Lurgi dry ash process, none of which are in the United States. At least a dozen projects, however, have been proposed or studied in the United States (Table A-1) (2). Of these, only the Great Plains Gasification Project in North Dakota appears to have potential for near term operations.

This Appendix is a supplement to the descriptive material and waste stream characterization data presented in Section 3 of this manual. As such, reference is frequently made to tables presented in Section 3, rather than present duplicative tables in this appendix.

A.1 PROCESS DESCRIPTION

A.1.1 Gasifier Equipment

The Lurgi gasifier is a veritical, cylindrical, water-jacketed, steel, pressure vessel (Figure A-1). Typically the Lurgi gasifier can vary in diameter from 2.5 to 4 m. It has an overall height of 5.8 m and a coal bed height that varies from 2.0 to 3.0 m. Atop the gasifier is a lockhopper through which coal is introduced into the reactor. Near the top of the

TABLE A-1. MAJOR PROPOSED COAL GASIFICATION PROJECTS USING LURGI GASIFIERS AS OF JANUARY 1982 (2)

Sponsor	Location
Hampshire Energy Company	Wyoming
WyCoal Gas Inc.	Wyoming
Lake Desmet Synfuels	Wyoming
Great Plains Gasification Associates	North Dakota
Nokota Company	North Dakota
North Dakota Synfuels Group	North Dakota
Tri-State Synfuels	Kentucky
Tenneco Coal Gasification	Montana
Crow Indians	Montana
Texas Eastern Synfuels	New Mexico
Exxon USA	Texas
Transco Energy Company	Texas
Louisiana Gasification Associates	Louisiana

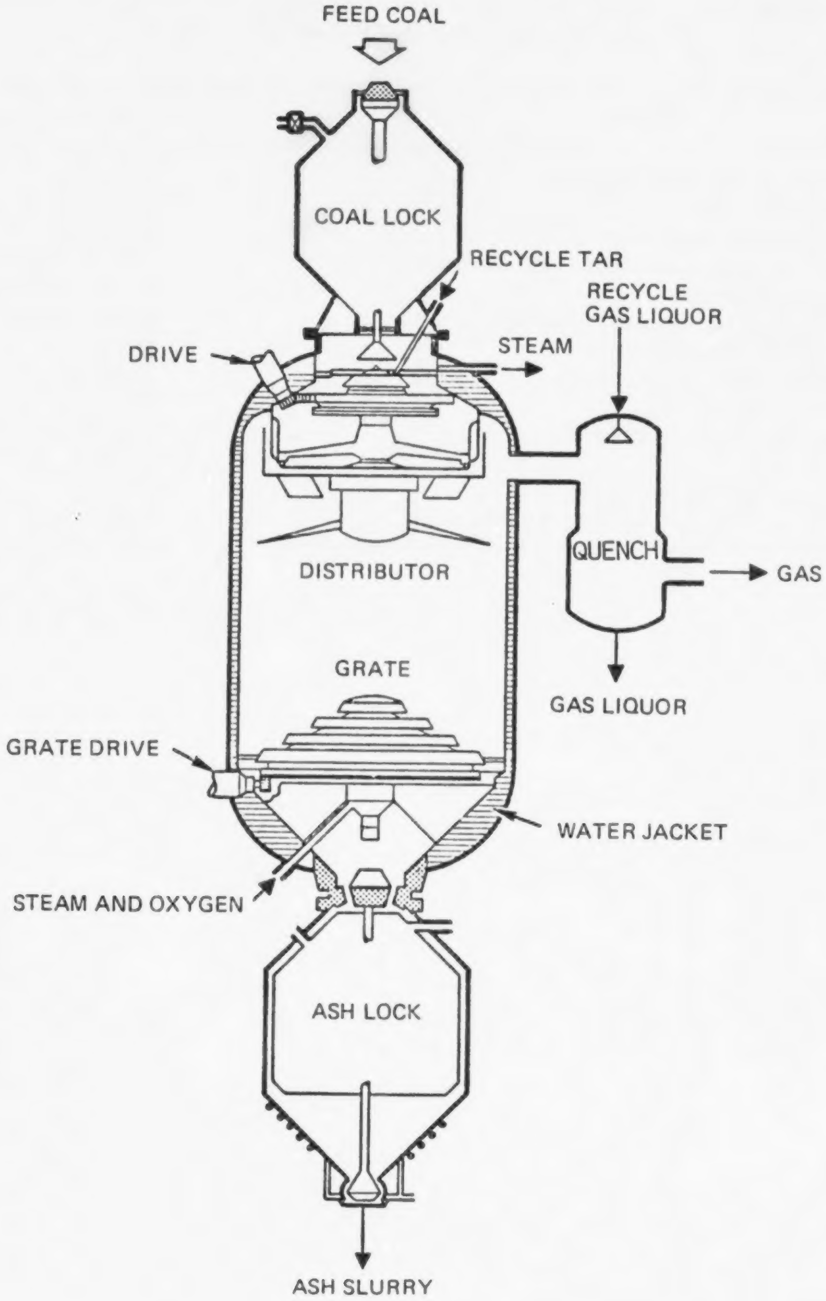

Figure A-1. Lurgi Dry Ash Gasifier

reactor is a watercooled, rotating coal distributor which helps to provide a uniform coal bed and to break up coal agglomerates. A recycle tar injection nozzle may also be located near the top of the gasifier. Tar injection helps reduce carryover of coal fines. An attachment to the Lurgi system is a gas quench and scrubber which removes condensibles from the raw gas.

Below the coal bed is a rotating grate which assists in the removal of ash through an ash lockhopper. Steam and oxygen are introduced into the gasifier below the ash extraction grate.

A.1.2 Operational Parameters

Devolatilization begins as the coal moves down through the gasifier and is combined with gasification at temperatures of 890 to 1030 K. The major chemical reactions which occur as the coal descends through the gasifier are as follows:

$\text{Coal} + \text{Heat} \rightarrow CH_x + H_2O$ (drying and devolatilization)

$C + H_2O + \text{Heat} \rightarrow CO + H_2$
$C + CO_2 + \text{Heat} \rightarrow 2CO$ (Gasification)
$C + 2H_2 \rightarrow CH_4 + \text{Heat}$

$2C + O_2 \rightarrow 2CO + \text{Heat}$ (Combustion)
$C + O_2 \rightarrow CO_2 + \text{Heat}$

Completion of the gasification process requires a minimum residence time of one hour at temperatures of 1030 to 1150 K (1). Gasifier pressure is maintained at 2.1 to 3.2 MPa. These operating conditions result in the high methane content in the raw Lurgi gas as well as the production of significant amounts of byproduct tars, oils, and phenols.

A.1.3 Feed Requirements

Many varieties of coal, lignite, and peat have been processed successfully in Lurgi gasifiers. Coal size can range from 3 to 60 mm with a typical range of 6 to 40 mm. Crushing and sizing are thus required in coal handling. Gasification of coals containing up to 40 percent moisture appears feasible.

Steam and either oxygen or air are the additional feeds to the gasifier. Use of oxygen results in the production of medium-Btu or synthesis gas while air gives rise to low-Btu gas. Oxygen requirements are indicated to range from 0.2 to 0.6 kg per kg of MAF (moisture and ash free) coal. From 1.5 to 3.1 kg of steam per kg of MAF coal have been used or proposed for the Lurgi gasifier. Data from Environmental Impact Statements for Lurgi-based facilities and typical data presented by Lurgi, however, indicate that a value less than 2 kg steam per kg MAF coal may be satisfactory. Of the steam required for gasification some 20% can be supplied from the gasifier jacket while the remainder must be supplied from external steam generators (1,3).

A.1.4. Raw Lurgi Gas

On a weight percent basis, raw Lurgi gas production will range from 42 to 50% of the total gasifier input. Table A-2 presents data on the components of interest in quenched Lurgi gas, excluding water. Four compounds: CO_2, H_2, CO, and CH_4, typically account for at least 97% of the dry gas. Other components of interest for which data were available are also presented. Sulfur compounds and hydrocarbons make up the bulk of the minor constituents. Most of the sulfur is recovered in downstream sulfur recovery systems after acid gas removal. About 15% of the non-methane organics will be recovered as naphtha in the acid gas removal (Rectisol) system.

TABLE A-2. QUENCHED LURGI GAS COMPOSITIONS

Component	Data Source					
	ANG[a]	Kosovo[b]	SASOL[c]	Westfield[d]		
				Rosebud	Pittsburg	Illinois
CO_2	32.5	21-40	28.8	28.8-30.4	30.8-31.5	31.1-32.6
CO	15.6	9.6-17	20.2	15.1-20.3	16.9-17.9	16.3-17.6
CH_4	10.8	8.9-14.5	8.8	11.2-12.2	8.4-9.0	8.7-9.4
H_2	38.8	36-46	40.1	36.5-41.1	38.8-39.4	38.5-39.8
C_2H_6	0.50	Tr-0.76	0.54	0.4-0.5	0.7	0.5-0.7
C_2H_4	0.07	Tr-0.11		0.1	0.1-0.3	0.1-0.3
C_3 Aliphatics	0.15	0.07-0.40		0.08	0.008-0.016	0.009-0.012
C_4 Aliphatics	0.11	0.02-0.24				
C_5 + Aliphatics	--	0.03-0.26				
Benzene	--	0.066-0.084		0.03-0.04	0.05-0.13	0.08-0.10
Toluene	--	0.020-0.026		0.01-0.02	0.016-0.029	0.02-0.03
Other Aromatics	--	0.0016-0.011		0.004-0.007	0.007	0.007-0.01
H_2S	0.35	0.44-0.78	0.28	0.5	0.7	1.1
COS	0.01	0.0063-0.012	<0.001	--	--	--
CH_3SH	0.01	0.046-0.07	0.002	--	--	--
C_2H_5SH	0.01	0.0098-0.027	0.002	--	--	--
HCN	--	0.0060-0.032		0.0002	0.0004-0.025	0.002-0.008
NH_3	0.96	0-0.0003		0.0001	0.0003	0.0001-0.0008
O_2	--	0.09-2.6		0.7	0.8-1.2	0.6-0.8
Ar	0.05	--	1.6	0.7	0.8-1.2	0.6-0.8
N_2	0.07	0.44-1.6	1.6	0.6	0.8-1.2	0.6-0.8
Temperature (K)	543	293-295		299	299	299
Pressure (MPa)	2.9	2.3		2.4	2.4	2.4

[a] Reference 4.
[b] Reference 5.
[c] Reference 6.
[d] Reference 3, range of values.
-- = No data.
Units are volume percent unless otherwise noted.

A.2 WASTE STREAMS

Waste streams directly from the gasifier are: low-pressure coal lockhopper vent gas, ash lockhopper vent gas, ash slurry, and gases released during transients (primarily startup). Waste streams from raw gas quenching/cooling and subsequent gas liquor separation include gas liquors and depressurization gases. Tars and oils represent byproducts recovered from gas liquors.

Prior to adding a fresh charge of coal to the lockhopper, it must be depressurized. Vent gases above 0.2 MPa are normally recovered while those below 0.2 MPa are not. Characteristics of the coal lockhopper vent gas are determined by the pressurant gas. If Lurgi gases were used as pressurant, the composition of the vent can be assumed similar to raw Lurgi gas. Testing at Kosovo (5) indicated a particulate loading of approximately 8 g/m³, most of which were aerosol organics.

Steam is utilized for pressurization of the ash lockhopper to minimize the flow of gasifier feed (i.e., steam and O_2) from the gasifier into the lockhopper. Before ash is discharged from the lockhopper to the ash quench system, it is depressurized. The resulting vent gases should contain only steam, O_2, and entrained ash particles. The only test data available on ash lockhopper vent gases is for the Kosovo plant (5). At this plant, the ash lockhopper gases are sent to a cyclone where they are contacted with process water (the source of the process water was not known). The cyclone exit gas contained 85 volume percent moisture and had the composition shown in Table A-3. For purposes of analysis in this manual though, ash lockhopper vent gases were assumed to contain 85 percent moisture, with the balance being O_2 and N_2 in the same ratio as found in the oxygen fed stream to the gasifier. Particulates were estimated at 10.3 g/m³ (dry basis).

TABLE A-3. AVAILABLE TEST DATA FOR ASH LOCKHOPPER VENT GAS (5)

Component	Quantity	Best Value
Moisture	81 - 97 wt %	85
O_2	48 vol % dry	48
N_2	35 vol % dry	35
CO_2	14 vol % dry	14
H_2S	0-82 ppmv dry	82
NH_3	130 - 340 ppmv dry	340
HCN	54 ppmv dry	54
Particulates	0.12 - 11.6 g/m^3	10.3

Hot ash is quenched with water in the ash lockhopper and then discharged. Quantities of ash produced are a function of the ash content of the coal. After dewatering, the ash results in solid waste. The results of analyses of gasifier ash from Kosovo (5), Westfield (3,7), and SASOL (6) are presented in Table A-4. Also included are values calculated from estimates of the distribution of elements in the gasifier ash from Dunn County coal (8).

Flow rates and compositions of transient streams are highly variable and data are scarce. Kosovo (5) and ANG (9) data characterizing transient gases generated during startup are presented in Table A-5. Kosovo data (5) also indicated that startup gases contained, after being subjected to quenching/ scrubbing, 0.06 and 9 g/Nm^3 of entrained particulate matter and aerosol organics, respectively. Kosovo data indicate that startup of a gasifier required approximately eight hours (5).

Prior to removal of tars and oils, the gas liquor is depressurized. Main components of the gases released during depressurization are given in Table 3-13. In the Westfield tests (3) the temperature varied somewhat during depressurization and the higher temperatures were stated to have led to higher NH_3 and CO_2 in the flash gas.

TABLE A-4. CHEMICAL COMPOSITION OF LURGI ASH

Components	Kosovo[a]	American Coals at Westfield[b]				SASOL[c]	Westfield[d]	Dunn County[e]
		Rosebud	Ill. No. 6	Ill. No. 5	Pitt. No. 8			
Carbon	12-26	6.5-4.8	3.2-2.1	2.0-1.0	7.6-4.6	3	2.8	--
SiO_2	25-36	46.8-46.9	49.6-50.7	46.1-44.6	43.6-44.9	52	54.6	19.4
Fe_2O_3	3.9-11	11.2-9.8	17.2-18.8	19.7-21.2	15.0-16.1	5	4.7	8.7
Al_2O_3	4.1-11	17.7-21.9	20.5-19.1	18.1-19.3	20.7-26.0	28	32.7	10.6
CaO	29-43	8.3-6.8	2.1-2.9	3.9-4.0	3.8-3.2	7	3.6	19.0
MgO	5.1-7.4	3.9-4.2	1.0-1.3	0.7-0.2	0.7-0.2	1.7	1.3	7.0
SO_3	0.36-5.8	1.7-1.0	1.3-1.2	0.6-0.04	0.8-<0.01	0.2	--	3.2
Cl	--	<0.01-<0.01	<0.01-<0.01	<0.01-<0.01	<0.01-<0.01	--	--	0.03
Na_2O	1.1-1.8	--	--	--	--	0.7	--	2.7
K_2O	0.4-0.8	--	--	--	--	0.5	--	0.5

[a] Reference 5.

[b] Reference 3: 2 samples per coal based on size, one at 1/4" to 1-1/4" and second with >30% at <1/4".

[c] Reference 6.

[d] Reference 7.

[e] Reference 8: calculated from data provided.

-- = No data.

Units are weight percent (dry basis).

TABLE A-5. GAS PHASE TEST DATA FOR GASIFIER STARTUP (COMPOSITION ON DRY BASIS)

Component	Kosovo[a] (Vol %)	ANG[b] (mol %)	Component	Kosovo[a] (ppmv)	ANG[b] (ppmv)
H_2	0.09-0.27	23.2	H_2S	6300	3000
O_2	4.4-18	--	COS	40-120	--
N_2	42-67	38.9	CH_3SH	90-520	--
CO	3.7-14	9.3	C_2H_5SH	30-250	--
CO_2	10-34	20.8	Benzene	10-90	--
CH_4	0.8-1.6	7.1	Toluene	TR-10	--
Ethane	0.07-0.16	--	Xylene + ethylbenzene	TR-10	--
Ethylene	0.004-0.05	--	Phenols	630	--
C_3	0.03-0.08	--	NH_3	11000	6000
C_4	Tr-0.04	--	HCN	2900	--
C_5	Tr-0.009	--			
C_6^+	0.03-0.09	--			

[a] Reference 5: moisture content 70 wt %, M.W. of dry gas ~33.1.
[b] Reference 9, moisture content 27.7 mol %.
Tr = trace.
-- = No data.

Tars and oils can be used on site as fuel, sold as byproducts, upgraded for blending with other facility products, or gasified in a partial oxidation type gasifier to produce additional synthesis gas. Properties of tars and oils are presented in Tables 3-30 and 3-33, respectively.

Gas liquor is the aqueous stream which results from quenching the raw Lurgi gases and removing tars and oils. Major components of the gas liquor prior to removal of phenols and ammonia are given in Table A-6. A distribution of selected organic compounds in the gas liquor is given in Table 3-15. Expected quantities of byproducts in the gas liquor per amount of coal gasified are given below (3,4,5,11,12). Also shown is the naphtha which is recovered from the Rectisol AGR system.

Components	Quantity Produced (percent of MAF coal gasified)
Tars	2.4 - 5.3
Oils	0.3 - 3.2
Phenols	0.3 - 1.1
Ammonia	0.6 - 1.3
Naphtha	0.9 - 2.0

A.3 ADVANTAGES AND LIMITATIONS

The dry ash Lurgi system can gasify a wide variety of coals including caking and non-caking coals. It has been in operation for many years, is commercially available, and is a relatively straight forward process. Its operating conditions favor the formation of methane, reduce the cost of gas transmission, and are advantageous for combined-cycle or synthesis gas utilization.

Operating conditions which favor methane formation also lead to the formation of heavy organic byproducts and materials which require additional processing. Coal bed temperatures below ash fushion temperatures limit

TABLE A-6. MAJOR COMPONENTS AND CHARACTERISTICS OF LURGI GAS LIQUOR

	Kosovo[a]	Westfield American Coals[b]				Bromel[c]	SASOL[d]
		Rosebud	Ill. No. 6	Ill. No. 5	Pitt. No. 8		
Tars and Oils	400	150-270	500-150	200-90	100-240	--	5000
Phenols (as C_6H_5OH)	2120	5000-5400	2200-2930	3550-3300	1450-1600	2480	3250-4000
Ammonia						11200	
Free	3510	7310-8930	4800-3990	5440-4390	3220-4090	--	10600
Fixed	250	300-470	150-260	310-220	350-250	--	150-200
Fatty Acids	--	1995-1050	370-375	390-350	205-260	226	300
Aromatic Amines	159	--	--	--	--	232	--
Organic Carbon	4970	--	--	--	--	2460	--
Sulfide (as H_2S)	--	55-330	290-240	320-340	120-220	<0.5	237
Thiocyanate (SCN)	>75	6-60	160-135	164-135	155-210	85	--
Total Sulfur	--	225-445	360-330	370-405	205-340	--	--
Carbonate (as CO_2)	--	13600-19960	7780-10620	5810-11020	7700-10650	--	7000
Cyanide (as CN)	<1	5-8	37-17	21-13	33-16	--	6
Chloride	--	25-9	95-80	230-165	195-160	--	--
TDS	2170	2480-1940	1860-1765	1640-2190	1310-1140	2460	--
COD	17700-18900	22800-18600	8900-9650	11000-9400	3500-5900	12500	--
BOD_5	9030	10600-12250	3600-9580	4600-5400	2700-4300	--	--
pH	9.1-9.2	8.2-8.1	7.8-7.7	7.9-7.8	7.7-7.6	8.9	--

[a] Reference 5.

[b] Reference 3 (sidestream liquor), 2 runs made for each coal; the first for coal size 1-1/4" to 1/4", the second contained at least 30% less than 1/4".

[c] Reference 10.

[d] Reference 6.

-- = No data.

Units are mg/L except pH.

process efficiency and increase steam requirements from outside sources. The fixed-bed reactor design limits the maximum size of the reactor, thus potentially making it more costly for large installations.

A.4 MASS FLOW ESTIMATES

Estimates of mass flows for three types of coal gasified by a Lurgi system were developed. These values were calculated from methods indicated in this section based on gasifying sufficient coal to produce approximately 120 TJ/day of synthesis gas. These methods involved the use of available data from which stream quantities and composition were derived or extrapolated. Several of the streams are thus a composite of available data. The result is that material balances are not exact but are generally within 1%. Details of the material balance results are presented in Appendix E.

The three coals selected include a subbituminous coal (Montana Rosebud), a bituminous coal (Illinois No. 6), and a lignite (Dunn County, ND). The composition of these coals is presented in Table 2-1. All three coals are plentiful in the United States and have been successfully gasified in a Lurgi system, with sufficient data gathered go enable estimation of gasification stream quantities and characteristics. These coals also represent different classes of coals and cover a range of moisture, ash, and sulfur contents.

A.4.1 Major Gaseous Constituents

Production of major gasifier output gases (H_2, CO, CO_2, and CH_4) were estimated from data and elemental material balances contained in a Westfield report (3) for tests on several bituminous and subbituminous coals and on data from Kosovo studies (5) or the EIS for the ANG SNG facility for lignite cases (4).

A.4.2 Sulfur Distribution

The quantity of sulfur contained in the quenched Lurgi gas stream was determined by subtracting that contained in the ash, tar, oil, and gas liquor (as discussed in subsequent sections) from that contained in the coal. The remaining sulfur was distributed among the following constituents: H_2S, COS, CH_3SH, C_2H_5SH, and C_3+ mercaptans. The distribution used was based on Kosovo data (5) and is given below:

Constituent	Mole %
H_2S	88.8
COS	1.2
CH_3SH	7.4
C_2H_5SH	2.3
C_3+ mercaptans	0.3

A.4.3 Hydrocarbon Distribution

The distribution of hydrocarbon species in the quenched Lurgi gas stream was based, for all coals, on the following assumptions:

- C_2 through C_4 aliphatics were based on the ANG EIS (4) which gives, by percent volume in raw dry Lurgi gas: 0.495 for C_2H_6; 0.07 for C_2H_4, C_3H_6, and C_4H_8; 0.08 for C_3H_8; and 0.04 for C_4H_{10}.

- C_5 aliphatics, benzene, toluene, and other aromatics were based on Westfield data for St. Clair de Ville condensibles (3). Distribution among these constituents was determined using Westfield's data for the analysis of condensible aromatic compounds. The production rate of these compounds was based on the following normalized flow rates from Westfield data: Rosebud, 0.01; and Illinois No. 6, 0.0109 kg per kg MAF coal. Dunn County production rate and distribution were assumed equivalent to Rosebud.

A.4.4 Hydrogen Cyanide and Ammonia

Hydrogen cyanide and ammonia in quenched Lurgi gas were assumed to be 60 and less than 10 ppmv, respectively, as estimated from Kosovo data (5). Quantities of NH_3 contained in the raw gas stream were obtained by adding that contained in the gas liquor and depressurization gas streams (given in following discussions). Due to variability in the available data and the feed coals, flow estimates may differ somewhat between examples.

A.4.5 Steam and Oxygen Feed

Steam and oxygen requirements for Rosebud and Illinois No. 6 coals were estimated from Westfield data (3). Feed requirements for Dunn lignite were estimated from data reported in the EIS for ANG's North Dakota project (4). Values used are given below:

Coal	Steam (kg/kg coal as received)	Oxygen (excludes inerts)
Rosebud	1.25	0.24
Illinois No. 6	2.5	0.45
Dunn County	1.06	0.21

A.4.6 Gas Liquor

Gas liquor flow rates were determined as follows: 1) total hydrogen and oxygen into the gasifier was computed; 2) total hydrogen and oxygen contained in the output constituents, other than in the gas liquor were computed; and 3) output quantities of hydrogen and oxygen were subtracted from input quantities and the difference allocated to the gas liquor stream. Gas liquor compositions are given in Table 3-14. For Rosebud and Illinois No. 6 cases, concentrations of major constituents were estimated from Westfield data (3). Concentrations of major constituents in the Dunn County case gas liquor were estimated from data contained in the Bromel report (10). The concentration of ammonia was normalized with respect to the ratio of coal nitrogen content of Mercer County (basis in Bromel report) and Dunn County coals. COD and TOC values were based upon data from References 8 and 10.

A.4.7 Low-Pressure Coal Lockhopper Vent Gas

Coal lockhopper vent gas flows were assumed to be proportional to the coal feed rate. Using the lock gas flow (excluding ejection or dilution air) of 37.2 kg-moles/hr for 1020 Mg coal per hour as estimated in the proposed ANG facility (4,9), a factor of 0.04 kg-moles of low-pressure vent gas per Mg coal feed was calculated. The low-pressure vent represents about 2% of the total coal lockhopper gases (9). The dry gas composition of the low-pressure lockhopper gases was assumed to be the same as the raw Lurgi gas with H_2O at 0.8 volume percent. Particulates in the vent gas were estimated at 0.2 g/Nm³ while aerosol organics were estimated at 7.3 g/Nm³ (5).

A.4.8 Ash Lockhopper Vent Gas

The flow rate of ash lockhopper vent gas was assumed to be proportional to the ash flow rate. Based on Kosovo data (5) a factor of 16 kg dry gas per 1000 kg dry ash was used. The composition of ash lockhopper vent gas was assumed to be 85 volume percent moisture based on Kosovo data (5) with the remainder being nitrogen and oxygen in the same ratio as found in the oxygen feed. A particulate loading of 10.3 g/Nm³ dry gas was assumed based on Kosovo data (5).

A.4.9 Gas Liquor Depressurization Gas

Gas liquor depressurization gas compositions were generally based on both Westfield (3) and Kosovo data (5). Flow rates for Rosebud and Illinois No. 6 coals were based on normalized Westfield data (quantity of depressurization gas produced per quantity of input coal to gasifier) (3). Flow rates for the Dunn County coal case were based on normalized Rosebud and Illinois No. 6 data. Water vapor content was based on data presented in Reference 13.

A.2.10 Chlorine

Chlorine distribution was computed in the following manner: 1) the quantity of input chlorine was calculated based on coal analysis; 2) 10 ppm HCl was assumed to be present in the quenched Lurgi gas; 3) HCl in gas liquor was calculated based on the assumed composition; and 4) the remaining chlorine was distributed to the gasifier ash.

A.4.11 Ash

Available data on the composition of Lurgi ash are summarized in Tables A-4 and 3-11. Ash sulfur and carbon contents were generally based on Westfield data (3) for Rosebud and Illinois No. 6 coals, and the ANG EIS (4) for the Dunn County case. Values used in mass flow calculations (weight percent basis) are given below:

	Rosebud	Illinois No. 6	Dunn County
S	0.68	0.56	1.24
C	6.59	3.19	6.5

A.4.12 Byproducts

Byproduct tar, oil, phenol, and fatty acid compositions for Rosebud and Illinois No. 6 coals were based on Westfield data (3). Since these data were not available for the Dunn County case, compositions were derived from the Westfield data.

Mass flow calculations for tar and oil are given below on an ash free basis.

	Tar (wt %)			Oil (wt %)		
	Rosebud	Illinois No. 6	Dunn Co.	Rosebud	Illinois No. 6	Dunn Co.
C	83.1	85.5	83.2	81.4	84.8	81.4
H	7.7	6.44	7.0	9.18	7.77	8.0
O	8.24	5.17	8.3	8.46	4.3	9.4
N	0.65	1.18	1.2	0.46	0.7	0.7
S	0.28	1.7	0.29	0.50	2.4	0.36

Tar ash content (total inert suspended material or dust) was assumed to be 7 wt percent, based on Westfield Illinois No. 6 (3) and Kosovo (5) data (note: Westfield Rosebud tar ash content data was inexplicably high). Oil ash content was assumed to be 0.2 wt percent based on Kosovo data (5).

Tar and oil production rates for Rosebud and Illinois No. 6 coals were based on Westfield data on a normalized basis (weight produced per weight of coal gasified) (3). These values (kg/10^3 kg coal) are given below:

	Tar	Oil
Rosebud	19	20.9
Illinois No. 6	30	2.9

Tar and oil production rates for Dunn County coal were based on values given in the ANG EIS (4) of 1.6 and 0.37 wt percent (wet basis), respectively, in the raw gas.

Phenol and fatty acid compositional data are given below (3). Production rates were determined by the assumed gas liquor concentrations previously discussed.

	Phenol (wt %)			Fatty Acids (wt %)		
	Rosebud	Illinois No. 6	Dunn Co.	Rosebud	Illinois No. 6	Dunn Co.
C	77.1	76.7	77.3	38.1	38.5	38.3
H	5.7	6.7	6.2	9.5	7.7	8.6
O	17.1	16.7	16.9	52.4	53.8	53.1

Naphtha is also a byproduct of Lurgi gasification when the raw gases are upgraded via the Rectisol process (see Appendix B). This naphtha fraction, composed of hydrocarbons containing at least four carbon atoms, sulfur compounds, and HCN is a function of hydrocarbon distribution in the raw gas and Rectisol operations.

A.4.13 Gasifier Transient Waste Gases

Gasifier transient waste gas composition, flow rate, emissions, and frequency of discharge were based on the following assumptions:

- The following gasifier startup information was derived from ANG permit application information (9):

Type of Maintenance	Type of Startup	Duration of Startup (hr)	Number of Startups per Year[a]
Scheduled overhaul	Cold (air)	8	13
Unscheduled			
long	Cold (air)	8	26
short	Hot (O_2)	<1	104

[a] Normalized from ANG permit information to number of gasifiers required for the plants evaluated in this manual

- Discharge volumes corresponding to cold and hot startup conditions were estimated as 11.5 and 18.8 kg-moles/min, respectively, based on ANG permit application information (9).

- Per ANG information (9), "worst case" conditions exist when two gasifiers are cold started simultaneously with one gasifier in the hot start mode. This results in a total volume of 41.8 kg-moles per minute.

- Composition of transient waste gas was estimated using the ANG data (9) listed in Table A-5. Entrained particulates and aerosol organics, after quenching/scrubbing, were estimated at 0.06 and 9 g/Nm^3, respectively, based on Kosovo data (5).

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11. Final Environmental Statement: Western Gasification Company (WESCO) Coal Gasification Project and Expansion of Navajo Mine by Utah International Inc. New Mexico, U.S. Dept. of the Interior Rep. No. FES 76-2, January 1976.

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APPENDIX B

RECTISOL ACID GAS REMOVAL PROCESS

APPENDIX B

RECTISOL ACID GAS REMOVAL PROCESS

B.1 PROCESS DESCRIPTION

Rectisol is an acid gas removal process which removes carbon dioxide, hydrogen sulfide, carbonyl sulfide, organic sulfur compounds, hydrogen cyanide, ammonia, benzene, and gum-forming hydrocarbons from synthesis gases by means of physical absorption in an organic solvent (especially cold methanol) at temperatures below 273 K. Operation is based upon the fact that these compounds, particularly the reduced sulfur species and carbon dioxide, are very soluble at high pressure in cold methanol and are readily recoverable by flash desorption. This is demonstrated in Figure B-1, which presents carbon dioxide solubility as a function of partial pressure (1). Consider, for example, the absorption of carbon dioxide at a partial pressure of 1.0 MPa. From Figure B-1 it is evident that at least 90 percent of the dissolved carbon dioxide may be desorbed by isothermal flashing at methanol temperatures of 258 K or lower.

Solubility data for compounds at a partial pressure of 0.1 MPa over methanol are presented in Figure B-2 (2). It should be noted that gas solubilities generally increase with increasing partial pressure but that solubility coefficients (the ratio of solubility to partial pressure) do not increase appreciably with pressure until partial pressures exceed 0.1 to 0.2 MPa. Solubility coefficients of hydrogen sulfide and carbon dioxide are seen to increase substantially with decreasing temperature while those of major product gases such as hydrogen, carbon monoxide, and methane are relatively temperature independent. For this reason, Rectisol absorption columns operate at low temperatures, typically in the range of 253 to 213 K (1,3,4). Low temperature operation also reduces solvent losses by reducing the partial pressure of methanol in the product streams.

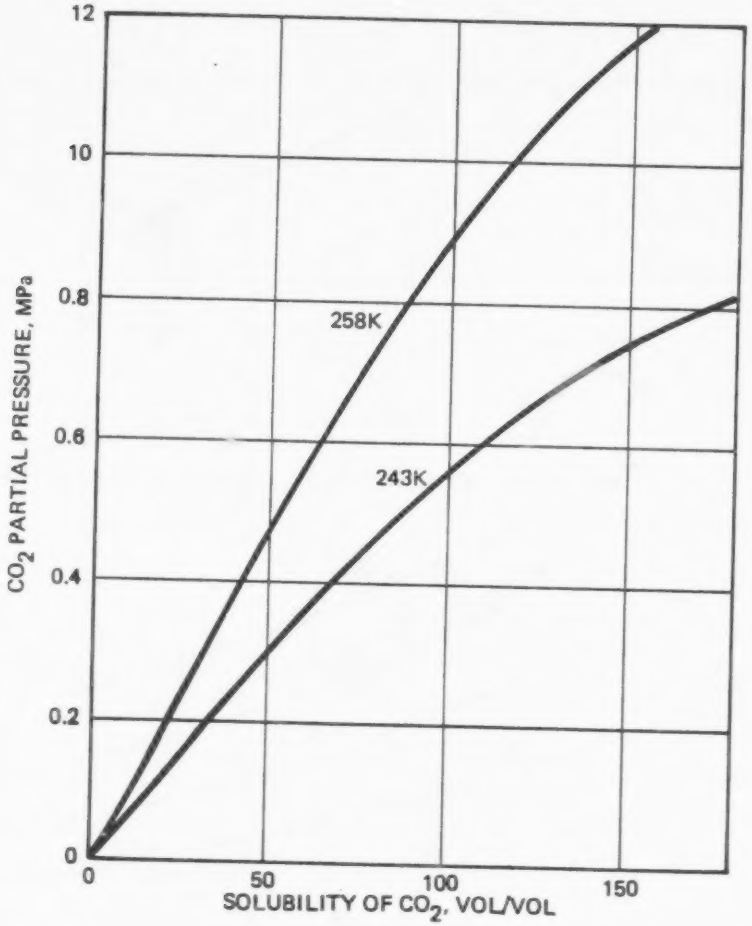

Figure B-1. Effect of partial pressure on solubility of carbon dioxide in methanol (1)

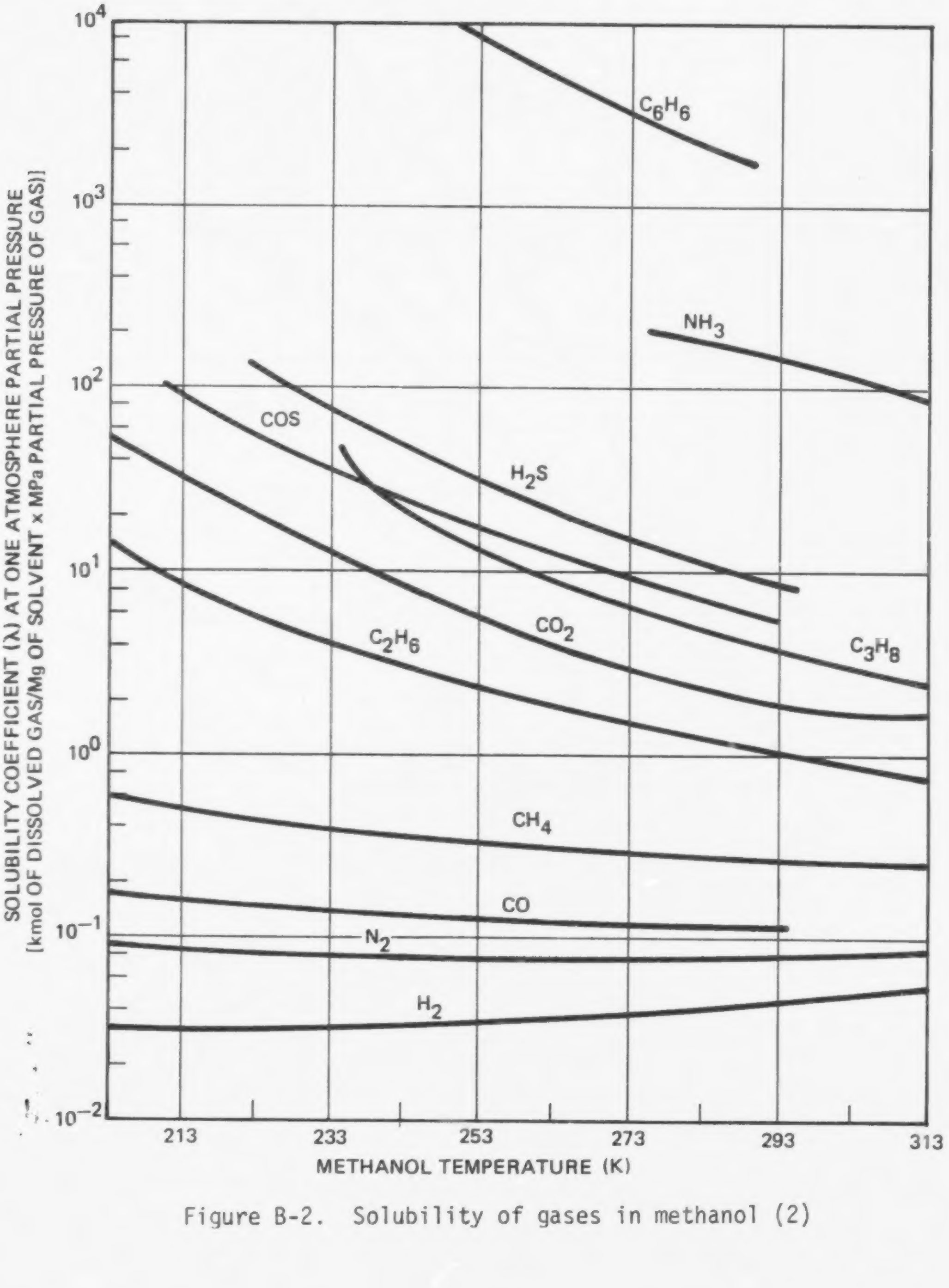

Figure B-2. Solubility of gases in methanol (2)

Because the solubilities of reduced sulfur species (e.g., hydrogen sulfide and carbonyl sulfide) in methanol are substantially greater than that of carbon dioxide at the same partial pressure, the Rectisol process is capable of selective recovery of reduced sulfur species versus carbon dioxide; to some degree, this holds for all physical absorption solvents capable of absorbing reduced sulfur species and carbon dioxide.

The Rectisol process was jointly developed by Linde Aktiengesellschaft (Munich, Germany) and Lurgi Mineraloltechnik (Frankfurt, Germany), and is currently licensed by both companies. It is also available through their U.S. subsidiaries, Lotepro Corp. (New York, NY) and Lurgi Corp. (River Edge, NJ), respectively. The Gelleschaft fur Kohle Technologie (GKT, Essen, Germany) also has a limited Rectisol license applying to Koppers-Totzek (K-T) gasification facilities.

Selective Rectisol Process Configurations

A variety of selective Rectisol units are currently being used in applications such as ammonia and methanol synthesis, medium-Btu gas synthesis, natural gas purification, and refinery hydrogen production. Although selective Rectisol designs are site- and process-specific, common key features include low temperature operation, sequential hydrogen sulfide-carbon dioxide absorption, discrete methanol regeneration columns for hydrogen sulfide and carbon dioxide recovery, and separation of methanol and water by distillation. However, there are significant differences among the designs in use which relate to both the feed gas composition and the product specifications.

Examples of selective Rectisol process configurations used in coal gasification applications are presented in Figures B-3 and B-4. The process presented in Figure B-3 is used by AECI Limited at Modderfontein, Republic of South Africa, and desulfurizes an essentially hydrocarbon-free quenched K-T

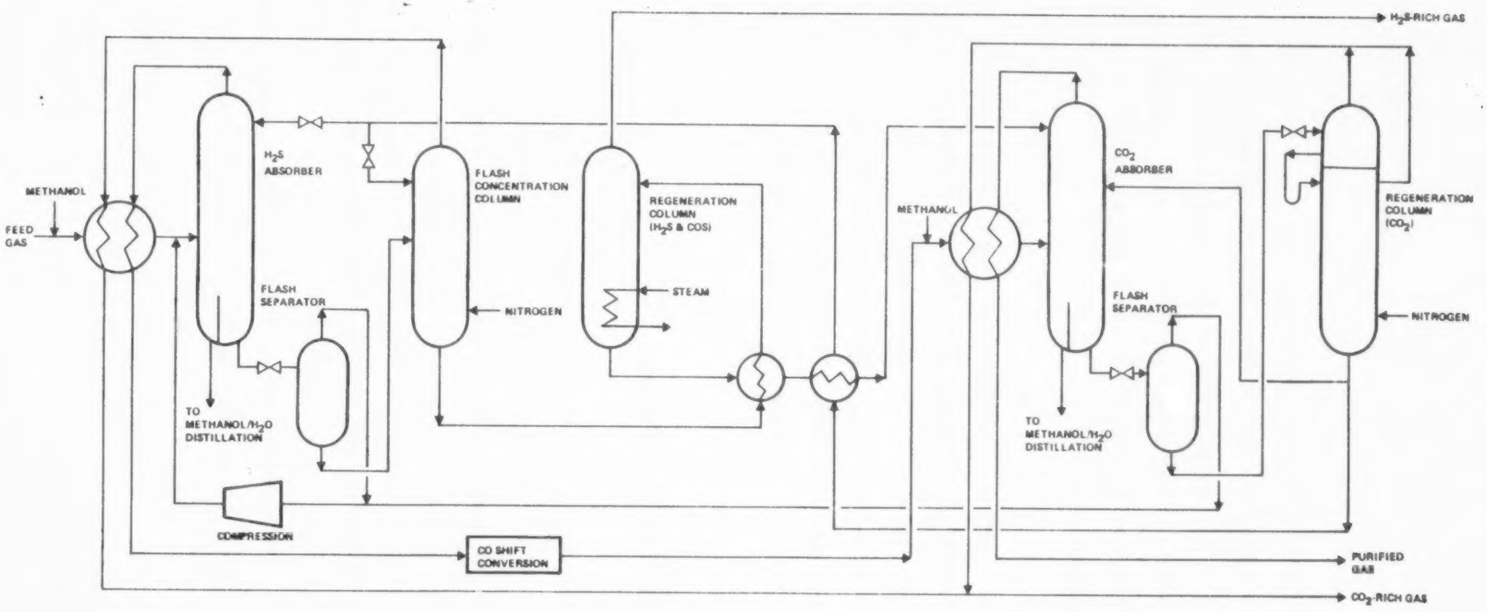

Figure B-3. Process flow diagram of the Modderfontein selective Rectisol section (5,6)

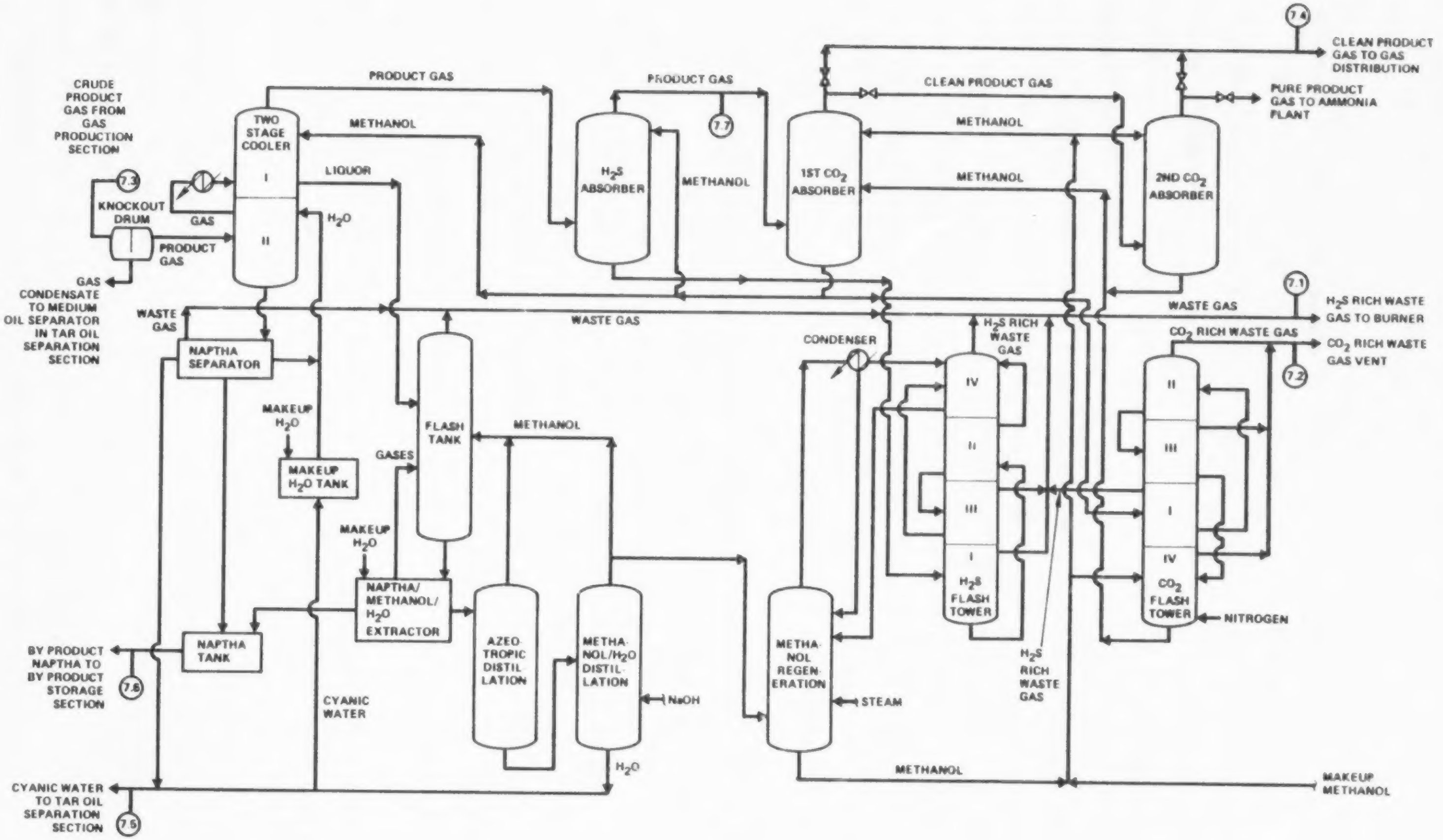

Figure B-4. Process flow diagram of the Kosovo selective Rectisol section (7,8) gas prior to carbon monoxide shift conversion and subsequent carbon dioxide removal (5,6). Methanol is added to the feed gas prior to cooling and hydrogen sulfide absorption to prevent icing. Moisture in the feed gas is removed from the hydrogen sulfide absorber in solution with methanol, which is recovered by distillation. Hydrogen sulfide and carbonyl sulfide are absorbed from the feed gas using sulfur-free methanol from the carbon dioxide regeneration column. Rich methanol from the hydrogen sulfide absorber is partially flashed to liberate absorbed hydrogen and carbon monoxide which is compressed and combined with the cold feed gas. Additional flashing and stripping in the concentration column, with reabsorption of reduced sulfur species in sulfur-free methanol, produces a sulfur-rich methanol stream for hot regeneration and a carbon dioxide offgas. Hydrogen sulfide is recovered by stripping with methanol vapor in the regeneration column.

Carbon dioxide is removed from shifted process gas by absorption in regenerated methanol. Methanol is added to the shift gas prior to cooling and carbon dioxide absorption to prevent icing, and moisture in the shift gas is removed from the carbon dioxide absorber in solution with methanol. Rich methanol from the carbon dioxide absorber is partially flashed to recover absorbed hydrogen which is compressed and combined with the cold feed gas to the hydrogen sulfide absorber. Carbon dioxide is recovered by flashing and stripping with nitrogen in the carbon dioxide regeneration column.

It should be noted that desulfurization prior to shift conversion enables the use of conventional shift catalysts (e.g., iron-chromium and copper-zinc) and can enhance process selectivity by absorbing hydrogen sulfide in the presence of a minimum of carbon dioxide (approximately 10 to 12 percent by volume for K-T coal gasification, 18 to 20 percent for Texaco coal gasification, and 5 to 6 percent for gas produced by partial oxidation of oil). However, in conjunction with partial oxidation of liquid hydrocarbons for hydrogen or ammonia production, shift conversion employing sulfur tolerant cobalt-molybdate shift catalysts precedes acid gas removal. Selective Rectisol configurations for such systems are similar to that presented in Figure B-3 except that no gas processing occurs between hydrogen sulfide absorption and carbon dioxide absorption. Shift conversion prior to acid gas removal results in an increased concentration of carbon dioxide in the hydrogen sulfide absorber feed gas (up to about 42 percent volume). Owing to the less favorable carbon dioxide to hydrogen sulfide ratio after shift conversion, a greater degree of methanol enrichment is required to achieve the same selectivity attainable with an unshifted feed gas.

The process presented in Figure B-4 is used at the Kosovo Gasification Plant near Pristina, Yugoslavia for the production of medium-Btu fuel gas and hydrogen for ammonia synthesis (7,8). Feed gas to the Rectisol unit is generated by gasification of lignite in oxygen-blown Lurgi-type gasifiers. Cooled crude gas from gasification is further cooled by sequential washing with cold water and methanol in the two stage cooler. Condensed gas liquor from the water wash section is flashed to liberate dissolved sour gases, and the organic phase is recovered from wash water in the naphtha separator. Condensed gas liquor from the cold methanol wash section is flashed, and methanol and condensed moisture are recovered from the naphtha phase by extraction with water. Dissolved organics in the aqueous phase are recovered by distillation. Naphtha from the naphtha separator and the naphtha/methanol/water extractor is sent to byproduct storage via the naphtha surge tank. Cyanic water from naphtha separation and methanol/water distillation is sent to tar/oil separation.

Gas from the two stage cooler is scrubbed with carbon dioxide-rich methanol in the hydrogen sulfide absorber for bulk removal of reduced sulfur species. Carbon dioxide is removed from the first absorber top gas in two carbon dioxide absorbers. Bulk carbon dioxide removal is achieved in the first absorber by washing with carbon dioxide-lean methanol and regenerated methanol. Overhead gas from the first carbon dioxide absorber is fed directly into the fuel gas distribution system. When a higher purity gas is required for feed to the cryogenic hydrogen separation unit, additional carbon dioxide removal is achieved in the second carbon dioxide absorber using regenerated methanol.

Hydrogen sulfide-rich methanol is regenerated by multistage flashing in the hydrogen sulfide flash tower, and steam stripping in the methanol regeneration column. Hydrogen sulfide-rich waste gas from methanol regeneration is combined with flash gas from the naphtha separator and the methanol prewash flash tank prior to disposal. Carbon dioxide-rich methanol is regenerated by multistage flashing and nitrogen stripping in the carbon dioxide flash tower.

Based upon publicly available data, it is not known how the Kosovo Rectisol design compares with other selective Rectisol units currently processing Lurgi crude gas. Several selective Rectisol designs have been prepared for proposed Lurgi gasification facilities in the United States (e.g., facilities for Wesco, El Paso Natural Gas Co., Hampshire Energy Co. and Nakota Co) (9). However, data with respect to process configuration are generally proprietary.

Configurations of the two units presented in Figures B-3 and B-4 differ in several respects. Principal differences result from 1) the fact that Lurgi crude gas contains significant levels of condensible hydrocarbons (approximately 0.01 kg C_5+ aliphatics, benzene, toluene, and other aromatics per kg MAF coal) which must be removed prior to acid gas removal (10), 2) the need for two-stage acid gas removal if sulfur intolerant catalysts are used for shift conversion, and 3) the fact that at Kosovo all hydrogen sulfide containing offgases are simply burned so that high hydrogen sulfide concentrations are not necessarily, as would be the case for Claus processing. These designs differ substantially wtih regard to selectivity. Differences in the performance of these two units are detailed in Section B.3.

Nonselective Rectisol Process Configurations

Nonselective Rectisol processes differ from selective processes in that all acid gas constituents are absorbed simultaneously and no carbon dioxide regenerator or reabsorber is used to produce a high purity carbon dioxide vent gas. An example of a commercial nonselective Rectisol unit is presented in Figure B-5 which is a simplified schematic of the South African Oil, Coal, and Gas Corporation's SASOL I acid gas removal system (1). Feed gas to acid gas removal is crude or partially shifted Lurgi gas from Fischer-Tropsch synthesis. The feed gas is split into three streams which are cooled in each of two stages by refrigeration, heat exchange with cold high pressure flash gas (including carbon dioxide-rich flash gases above 100 kPa) and heat exchange with cold product gas. Condensed moisture and hydrocarbons are recovered from the combined feed gas following the first cooling stage, and methanol is added to prevent icing in the second gas cooling stage. Following the second gas cooling stage, the condensed gas liquor is recovered from the coal gas and sent to the naphtha separator for byproduct and methanol recovery.

Cooled gas is washed with cold methanol in three consecutive stages. In the first absorption or prewash stage, the cooled gas is washed with flashed methanol from the expansion tower to remove the final traces of condensible organics along with some hydrogen sulfide, carbon dioxide, and organic sulfur compounds. Rich methanol from the first stage absorber is combined with gas liquor from the gas cooling second stage and sent to the naphtha separator. Separator feed is flashed and extracted with water to yield an aqueous methanol phase and a byproduct naphtha phase containing organic sulfur compounds. Methanol is recovered from the aqueous phase by distillation.

Bulk acid gas removal is achieved in the second or main wash stage or absorber by washing with flashed methanol from the expansion tower. Rich methanol from the second stage absorber is regenerated along with the

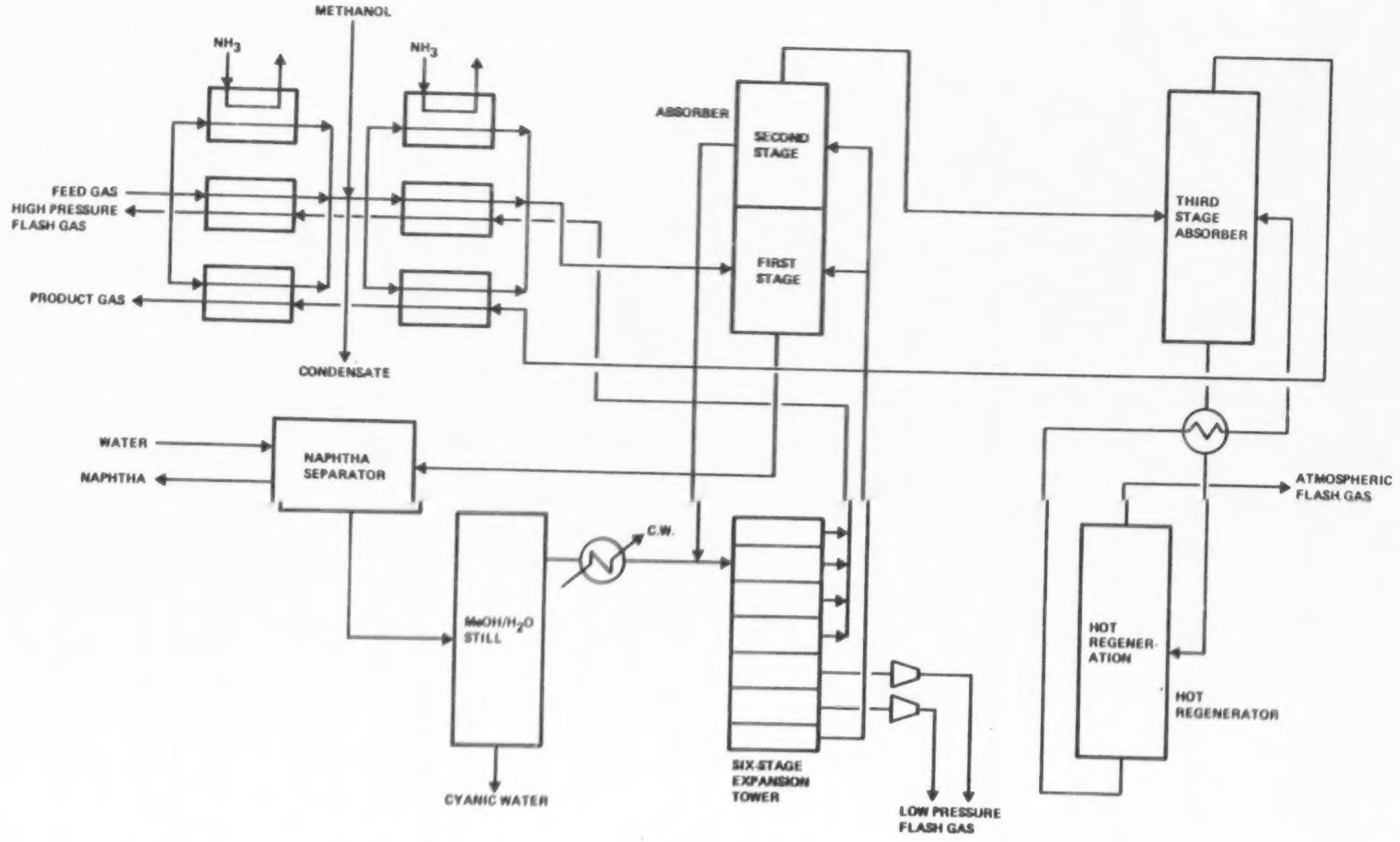

Figure B-5. Process flow diagram of the SASOL I non-selective Recitsol section (1) methanol/water still overhead in an expansion tower. Regeneration is by pressure reduction in six stages to a final pressure of about 30 KPa. High pressure flash gas consisting primarily of carbon dioxide, carbon monoxide, and hydrogen is used to cool the Rectisol feed gas, and then used as onsite fuel gas. Low pressure flash gas is compressed and flared.

The third or finewash stage absorber effects final gas purification by washing the second-stage absorber effluent gas with completely stripped methanol from the hot regenerator. Rich methanol from the third-stage absorber is partly regenerated by flashing to atmospheric pressure and then competely stripped of acid gas in a distillation column. Atmospheric flash gas from the hot regenerator is released for incineration. Cold product gas is used to precool the Rectisol feed gas, and then sent to liquid synthesis.

Based upon publicly available data, it is not known how the SASOL I Rectisol design compares with other commercial nonselective Rectisol processes, although a similar design has been used in the SASOL II facility which was commissioned in 1980 (11). Nonselective Rectisol designs have been prepared for several proposed Lurgi gasification facilities in the United States including those proposed by Great Plains Gasification Associates (currently under construction), Wycoalgas Inc., Tenneco Coal Gasification, and El Paso Natural Gas Co. (9,12). A schematic of the Great Plains nonselective Rectisol section is presented in Figure B-6 (13). This schematic indicates a similar configuration to that of the SASOL I facility but includes details such as the prewash flash vessel and the azeotrope distillation column which are not included in Figure B-5.

B.2 PROCESS APPLICABILITY

The Rectisol process is used in three typical applications: 1) removal of carbon dioxide, hydrogen sulfide, carbonyl sulfide, organic sulfur compounds,

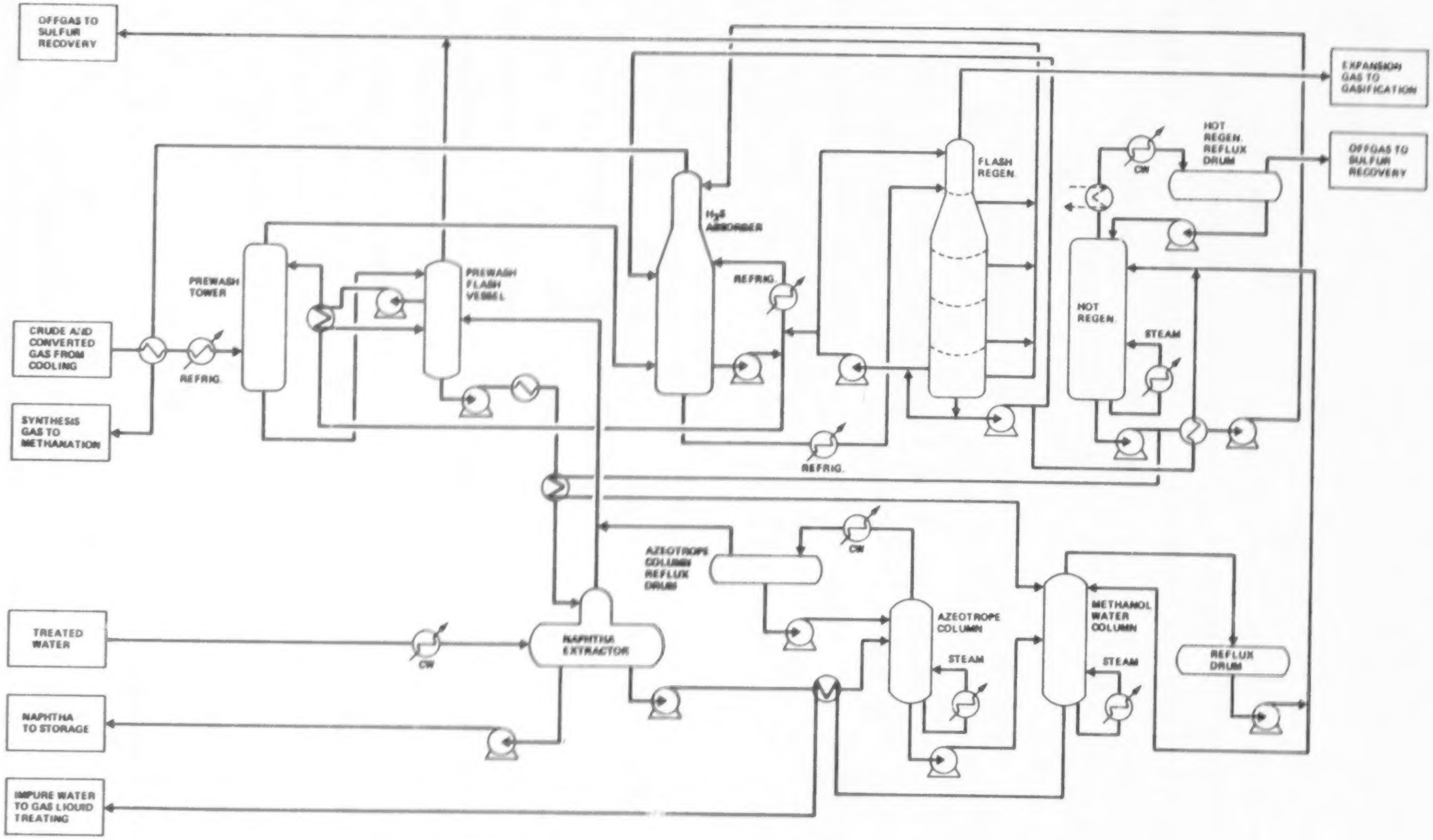

Figure B-6. Process flow diagram of the Great Plains non-selective Rectisol section (13) hydrogen cyanide, ammonia, benzene, and gum-forming hydrocarbons from crude gas produced by coal gasification for syngas and SNG production; 2) removal of hydrogen sulfide, carbonyl sulfide, and carbon dioxide from gas produced by partial oxidation for syngas or hydrogen production; and 3) used in conjunction with low temperature liquefaction and fractionation plants for removal of acidic components present at moderate levels. Process limitations in these applications primarily relate to requirements for high pressure, low temperature operation, and methanol contamination by minor constituents present in the feed gas.

As with any other physical absorption process, the minimum circulation rate of solvent required for complete removal of a gaseous constituent is inversely proportional to the partial pressure of the constituent in the feed gas, and to the solubility coefficient for the constituent in the solvent used. Process economics depend mainly upon the solvent circulation rate because the circulation rate influences the size of all equipment and, therefore, the capital costs. Solvent circulation rate also affects the operating costs since pumping costs are proportional to circulation rate and regeneration costs are nearly proportional to the circulation rate (14). Therefore, the economics of physical absorption processes improves with increasing acid gas partial pressures. Physical solvent type acid gas removal processes are typically selected when acid gas partial pressures are greater than about 1.0 to 1.4 MPa (1,15). Feed acid gas partial pressures at existing Rectisol units in coal gasification and partial oxidation applications are in the range of 0.4 to 2.6 MPa (3,5,6).

As indicated in Figure B-2, the solubilities of most gases of interest increase with decreasing methanol temperature. Thus, for reasons mentioned above, Rectisol economics improve with decreasing methanol temperature. Rectisol absorption columns operate at low temperatures, typically in the range of 253 to 213 K (1,3,4). An additional benefit of low temperature operation is the attendant reduction of methanol losses. Vapor pressure data for methanol are presented in Figure B-7 (1). These data indicate that methanol losses can be decreased by a factor of about three to four for each 20 K temperature reduction down to 253 K and by about one order of magnitude for each 20 K temperature reduction below 253 K.

Minor constituents such as ammonia, hydrogen cyanide, and nitrogen oxides which may be present in the Rectisol feed gas can complicate operation or result in fouling. Ammonia and hydrogen cyanide, which are very soluble in methanol, make the regeneration process more complicated and result in additional steam requirements (2). Further, the presence of ammonia and hydrogen cyanide in the hydrogen sulfide fraction is not desirable due to the potential for adverse reactions during subsequent sulfur recovery. These contaminants may be removed from the feed gas by employing a prewash of either cold water or methanol. This prewash also provides feed gas drying (particularly the methanol prewash) and, in low temperature gasification applications, removes condensible hydrocarbons.

One coal gasification facility has reported Rectisol fouling which is attributed to the presence of oxygen and nitrogen oxides in the Rectisol feed gas (16,21). Oxygen in the Rectisol feed gas results in oxidation of a portion of the hydrogen sulfide to elemental sulfur. The presence of nitric oxide with oxygen accelerates the rate of sulfide oxidation. Deposits of sulfur in columns resulted in reduced solvent circulation rates, and fouling of heat exchangers resulted in insufficient cooling capability to achieve the required degree of gas purification.

It has been determined that this fouling can be reduced by allowing low levels of hydrogen cyanide and ammonia to enter the Rectisol unit to solubilize sulfur by formation of ammonium thiocyanate which is ultimately removed with the methanol/water distillation bottoms. When insufficient hydrogen

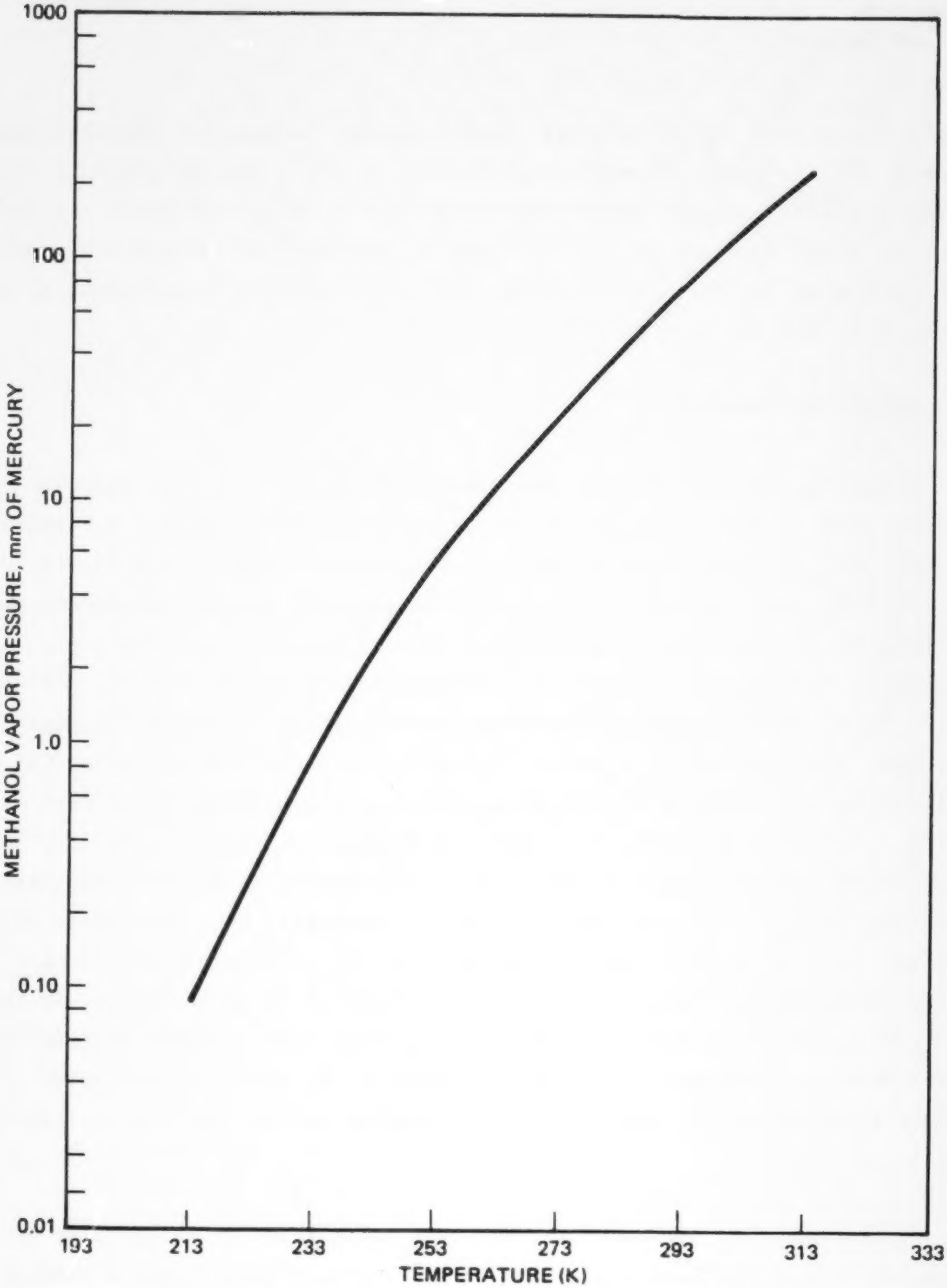

Figure B-7. Vapor pressure of methanol (1) cyanide is present in the feed gas, sodium cyanide solution is injected into the methanol. A more fundamental solution which has been implemented is the hydrogenation of nitrogen oxides and oxygen over a cobalt molybdate catalyst upstream of the Rectisol unit. Formation of elemental sulfur and the associated fouling of the Rectisol unit have not occurred since installation of the catalytic hydrogenation unit (21).

B.3 PROCESS PERFORMANCE

Depending upon the product requirements and other site specific constraints, the Rectisol process can be designed to yield a product gas containing less than 0.1 ppmv total sulfur, and less than 10 ppmv carbon dioxide. The carbon dioxide content achievable in the purified gas is independent of the type of Rectisol process employed (i.e., selective or nonselective Rectisol). However, in the case of a nonselective Rectisol process, the utilities (steam, cooling water, and refrigerant) increase to obtain a product gas with ppmv levels of carbon dioxide. Publicly available data indicate that in gasification applications involving an essentially hydrocarbon-free feed gas, selective Rectisol processes can produce a sulfur-rich offgas containing 25-75% hydrogen sulfide, and a carbon dioxide-rich offgas containing less than 10 ppmv total sulfur. The presence of moderate quantities of hydrocarbons in the feed gas (9 to 16 percent) has no influence on the selectivity of hydrogen sulfide recovery; hydrogen sulfide concentrations of 25 to 35 percent in the hydrogen sulfide-rich offgas can be achieved along with a carbon dioxide-rich offgas containing 10 ppmv total sulfur. However, C_3 and C_4 hydrocarbons present in the feed gas, will tend to concentrate in the hydrogen sulfide-rich offgas.

Performance data for selective Rectisol units treating essentially hydrocarbon free feed gases are summarized in Table B-1. Plants 1 and 2 produce hydrogen and ammonia synthesis gas, respectively, by partial oxidation of

TABLE B-1. SELECTIVE RECTISOL PERFORMANCE DATA FOR HIGH TEMPERATURE GASIFICATION APPLICATIONS[a]

Gas Component	Feed Gas, Mole %			Purified Gas, Mole %			Stripping Gas, Mole %			CO_2-Rich Offgas, Mole %			H_2S-Rich Offgas, Mole %		
	Plant 1	Plant 2	Plant 3	Plant 1	Plant 2	Plant 3	Plant 1	Plant 2	Plant 3	Plant 1	Plant 2	Plant 3[b]	Plant 1	Plant 2	Plant 3
H_2	62.35-63.74	61.59	27.5-29.3	93.58-94.08	94.92	93.0-93.2				0.31-0.33	0.76	0.40-0.44	-	-	-
N_2+Ar	0.12-0.52	0.41	1.52	0.17-0.82	0.67	1.78	100	100	100	17.2-19.3	8.22	12.1-14.5	0.08	1.92	2.5-8.4
CO	3.24-4.13	2.60	56.62	4.86	3.94	4.97-5.15				0.08-0.14	0.11	0.34-0.43	-	-	-
CH_4	0.13-0.17	0.33	0.10	0.19 0.24	0.47	0.10				≤0.02	0.06	0.01	-	-	-
CO_2	31.62-33.23	34.55	11.8-13.3	≤10ppm	50ppm	≤50ppm				80.2-82.4	90.85	84.7-87.0	54.7-74.7	68.31	10.6-
H_2S	0.26-0.49	0.52	0.59-0.75	≤1ppm	1ppm	<2ppm				2-5ppm	5 ppm	<5ppm	25.2-35.1	29.77	25.5-71.9[c]
COS	10-63ppm	-	0.10	-	-	-				8ppm	-	<2ppm	0.08-0.76	-	9.54[d]
Flow Rate, kmol/hr	3562-3992	6112	4691-4801	2426-2639	3950	4078-4096	268	187	334-543	1370-1567	2243	2731-3690	30-55	107	48-108
Temperature, K	303-313	-	311	295-309	-	304	303	-	311	295-303	-	302	303-322	-	311
Pressure, MPa	3.2-3.3	7.3	3.0-3.1	2.9-3.1	7.1	4.8	0.25	0.49	0.26-0.44	0.10	0.11	0.097	0.40-0.44	0.19	0.24-0.26

[a] Plant 1 is a refinery producing hydrogen by partial oxidation of oil; shift conversion occurs prior to acid gas removal (2,6,17).
Plant 2 produces ammonia synthesis gas from crude hydrogen generated by partial oxidation; shift conversion occurs prior to acid gas removal (3).
Plant 3 produces ammonia synthesis gas by coal gasification; shift conversion follows hydrogen sulfide removal but precedes carbon dioxide removal (2,6).
Refer to Figure B-3 for example process flow diagram. Sulfur-free gas is compressed prior to shift conversion.

[b] Concentrations of HCN and NH_3 in the CO_2-rich offgas at Plant 3 are 14 ppmv and 12 ppmv, respectively (5,6).

[c] Higher hydrogen sulfide concentrations require more refrigeration and more stripping gas.

[d] A COS level of about 3.4 mole percent would be expected with an H_2S concentration of 25.5 mole percent.

oil. These plants utilize sulfur-tolerant shift conversion catalysts which enable shift conversion prior to acid gas removal. Therefore, the feed gases to Plants 1 and 2 contain 31 to 35% carbon dioxide, 62 to 64% hydrogen, and less than about 5% carbon monoxide (2,3,6,17). Plant 3 is a coal gasification facility producing ammonia synthesis gas. This plant employs a two-stage Rectisol system which removes sulfur species prior to shift conversion and removes carbon dioxide subsequent to shift conversion (refer to Figure B-3 for example process flow diagram). Feed gas to the Plant 3 sulfur absorber therefore contains only 12-13% carbon dioxide, 27-29% hydrogen, and about 57% carbon monoxide (2,6). Feed gas to the carbon dioxide absorber, which is not included in Table B-1, contains 42-43% carbon dioxide, 53-54% hydrogen, and about 3% carbon monoxide.

These selective Rectisol units are seen to perform similarly in most respects over a wide range of operating pressures although there is a substantial range in the concentration of hydrogen sulfide, 25-72%, in the sulfur-rich waste gas from Plant 3. Lotepro Corporation has indicated that the higher hydrogen sulfide concentration is attainable at the expense of higher refrigeration and stripping gas requirements (6). The amount of stripping gas is a function of the hydrogen sulfide concentration desired in the hydrogen sulfide-rich offgas, the type of Rectisol process, the feed gas pressure, and the carbon dioxide, hydrogen sulfide, and carbonyl sulfide concentrations in the feed gas. Under given conditions, an increase in stripping gas of about 60% is necessary to increase the hydrogen sulfide concentration from 25 to 70%.

Performance data for the Kosovo selective Rectisol unit (taken at partial load and not fully representative of normal performance), which treats crude gas from Lurgi-type gasification, are summarized in Table B-2 (refer to Figure B-4 for the process flow diagram). Data were obtained during three sampling

TABLE B-2. PERFORMANCE DATA FOR SELECTIVE RECTISOL UNIT AT KOSOVO MEDIUM-BTU COAL GASIFICATION PLANT (7,18)[a]

Gas Component	Crude Product Gas (Stream 7.3), Mole % Value[b]	Crude Product Gas (Stream 7.3), Mole % Range	Clean Product Gas (Stream 7.4), Mole % Value[b]	Clean Product Gas (Stream 7.4), Mole % Range	CO_2-Rich Waste Gas (Stream 7.2), Mole % Value[b]	CO_2-Rich Waste Gas (Stream 7.2), Mole % Range	H_2S-Rich Waste Gas (Stream 7.1), Mole % Value[b]	H_2S-Rich Waste Gas (Stream 7.1), Mole % Range	Cyanic Water (Stream 7.5) Value[b]	Cyanic Water (Stream 7.5) Range
H_2	38.1	36-46	60	59-67	~0.01	<0.01-0.8	0.11	0.02-0.11		
O_2	0.36	0.09-2.6	0.44	0.1-1.7	~0.01	~0.01-1.8	~0.01	~0.01-0.51		
N_2	0.64	0.04-1.6	0.38	0.32-6.8	~0.01	~0.01-48	~0.01	~0.01-3.2		
CO	15	9.6-17	22	13-23	~0.01	<0.01-0.01	1.1	1.1-3.5		
CO_2	32	21-40	0.02	<0.01-2.4	94	91-95	88	85-92		
CH_4	11.5	8.9-14.5	16	12-18	1.2	0.6-1.8	4.3	4.1-4.7		
C_2H_4	0.47	~1ppmv-0.76	0.15	~1ppmv-0.18	1.6	0.29-1.6	0.82	0.34-0.97		
C_2H_6	0.04	~1ppmv-0.11	~1ppmv	—	~1ppmv	—	~1ppmv	—		
C_3	0.19	0.07-0.40	~1ppmv	~1ppmv-0.09	0.28	0.17-0.55	0.63	0.22-1.1		
C_4	0.074	0.02-0.24	~1ppmv	—	~1ppmv	<1ppmv-0.23	0.32	0.14-0.58		
C_5	0.044	0.01-0.06	~1ppmv	—	~1ppmv	<1ppmv-0.17	0.04	0.03-0.21		
C_6	0.064	0.02-0.20	0.03	<1ppmv-0.03	<1ppmv	—	0.21	0.01-0.22		
Benzene	750ppmv	660-840ppmv	—	—	1ppmv	—	110ppmv	40-110ppmv		
Toluene	230ppmv	200-260ppmv	—	—	~1ppmv	—	8ppmv	4-8ppmv		
Xylene and Ethylbenzene	100ppmv	16-110ppmv	—	—	~1ppmv	—	<1ppmv	—		
Phenols	~1ppmv	—	~1ppmv	—	<1ppmv	—	~1ppmv	—		
H_2S	0.60	0.44-0.78	<1ppmv	—	39ppmv	20-90ppmv	4.54	1.6-5.0		
COS	97ppmv	63-120ppmv	0.17ppmv	<1-0.2ppmv	62ppmv	~1-62ppmv	420ppmv	360-540ppmv		
CH_3SH	590ppmv	460-700ppmv	1.1ppmv	~1-1.9ppmv	8.5ppmv	8.2-9.7ppmv	0.21	0.19-0.48		
C_2H_5SH	3.3ppmv	<1-3.3ppmv	~1ppmv	<1-30ppmv	4.6ppmv	<1-4.6ppmv	0.22	<1ppmv-0.22		
HCN	320ppmv	60-320ppmv	—	—	13ppmv		200ppmv	83-200ppmv		
pH									11.9	11.4-12.1
Total Solids, mg/L									730	—
Total Nonvolatile Solids, mg/L									450	—
Total Suspended Solids, mg/L									140	—
Total Dissolved Solids, mg/L									590	—
COD (as mgO_2/L)									205	—
Permanganate (as mgO_2/L)									570	—
Total Sulfur, mg/L									60	52-68
Flow Rate, kmol/hr	703		491		90		102			
Flow Rate, m^3/hr									0.8	—
Temperature, K	295	293-295	—	—	292	—	285		353	—

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[a] Refer to Figure B-4 for process flow diagram.
[b] Values are best overall values from available data.

campaigns in the period of September 1977 to November 1978. Tabulated data represent the best overall data obtained during these tests, and the ranges of the available data. As indicated previously, the presence of moderate levels of hydrocarbons in the feed gas has no influence on process selectivity. Differences in process selectivities indicated in Tables B-1 and B-2 primarily reflect differences in process requirements. At the Kosovo facility, the sulfur-containing gases are burned and, therefore, high sulfur concentrations in these offgases are not necessary. Thus, unlike the facilities cited in Table B-1, the Kosovo facility does not utilize an enrichment stage. Also, Kosovo's hydrogen and methane rich flash gases from the carbon dioxide and hydrogen sulfide loaded methanol streams are added to the hydrogen sulfide fraction rather than being recycled to the feed gas.

Available performance data for the SASOL I nonselective Rectisol unit, which also treats crude gas from Lurgi gasification, are presented in Table B-3 (refer to Figure B-5 for the process flow diagram). As initially designed, the high pressure flash gas is used as an onsite fuel gas, the low pressure flash gas is flared, and the atmospheric flash gas is vented to the atmosphere through the power stack (19). More recently, a Stretford unit was designed to treat the atmospheric flash gas which contains about 90% of the sulfur species absorbed (17,19). Proposed designs for U.S. facilities indicate that at least a portion of the high pressure flash gas is recycled to the gasification plant for recovery of carbon monoxide, hydrogen, and methane; some fraction of the high pressure flash gas may be combined with the other waste gases for sulfur recovery (12,20). Therefore, the performance indicated in Table B-3 may require some adjustment.

TABLE B-3. NON-SELECTIVE RECTISOL PERFORMANCE DATA FOR SASOL I (LURGI GASIFICATION) (17)[a]

Gas Component	Rectisol Feed Gas, Mole %	Product Gas, Mole %	Offgases, Mole % High-Pressure Flash Gas	Offgases, Mole % Low-Pressure Flash Gas	Offgases, Mole % Atmospheric Flash Gas
H_2	40.05	57.30	21.4	2.6	0.14
CO	20.20	28.40	18.2	4.8	0.0
CH_4	8.84	11.38	11.4	7.2	0.9
CO_2	28.78	0.93	46.7	83.4	97.2
N_2+Ar	1.59	1.77	1.5	0.8	0.03
H_2S	0.30	ND	0.32	0.49	0.88
COS	10ppmv	NA	NA	NA	30ppmv
CS_2	NA	NA	NA	NA	2ppmv
RSH	20ppmv	NA	NA	NA	280ppmv
Thiophene	NA	NA	NA	NA	2ppmv
Total Sulfur	NA	0.04ppmv	NA	NA	NA
C_2^+	0.54	–	0.7	1.1	0.7
Flow Rate, Nm^3/hr	381,000	263,000	4,600	15,000	98,000
Temperature, K	303	288	273	273	268
Pressure, MPa	2.6	2.4	1.3	0.48	0,11

[a] Refer to Figure B-5 for process flow diagram.

B.4 SECONDARY WASTE GENERATION

Secondary waste streams produced by the Rectisol acid gas removal process are: 1) hydrogen sulfide-rich offgases; 2) carbon dioxide-rich offgases (selective Rectisol processes only); and 3) methanol/water distillation bottoms. Available characterization data for the offgas streams have been summarized in Section B.3 for each of the three basic Rectisol process configurations. The sulfur-rich offgas is typically sent to the sulfur recovery unit, either Claus or Stretford, or flared. When the Rectisol process is used in conjunction with low temperature coal gasification systems (e.g., Lurgi gasifiers) the Rectisol feed gas contains significant concentrations of C_2 hydrocarbons relative to the concentration of hydrogen sulfide. The naphtha fraction is recovered from the feed gas by washing prior to acid gas removal. Lighter hydrocarbons largely pass through the prewash and are, to some extent, absorbed with the acid gases. These light hydrocarbons, particularly the C_3s and C_4s, tend to concentrate in the hydrogen sulfide-rich offgas and may also be present in the carbon dioxide-rich offgas. Therefore, unless special precautions are taken, high levels of these C_3 and C_4 hydrocarbons in the Rectisol feed gas may result in off-color sulfur if Claus sulfur recovery is employed or excessive tail gas hydrocarbon emissions if Stretford sulfur recovery is employed. An approach proposed in conjunction with Wesco and Hampshire Energy Co. selective Rectisol units involves the use of an amine unit (ADIP) to separate hydrocarbons from the Claus feed gas (9,20).

The carbon dioxide-rich offgas from selective Rectisol units is either sold as byproduct or vented to the atmosphere at existing facilities. As discussed above, light hydrocarbons present in the Rectisol feed gas are coabsorbed to some extent with the acid gases and may be present in the carbon dioxide-rich offgas. Further, steps taken within the Rectisol process to minimize hydrocarbon levels in the hydrogen sulfide fraction will likely result in increased hydrocarbons levels in the carbon dioxide offgases.

Similarly, carbon monoxide is coabsorbed and will be present in the carbon dioxide-rich offgas due to its low solubility in methanol. Of course the extent of carbon monoxide coabsorption, and therefore its potential concentration in the carbon dioxide-rich offgas, depends upon its partial pressure. Thus, for similar acid gas removal systems, processes requiring only a partial shift conversion (e.g., SNG, methanol, or acetic acid syntheses) would be prone to higher concentrations of carbon monoxide in the carbon dioxide-rich offgas. Therefore, proposed designs in Lurgi-based coal gasification applications indicate either incineration of the carbon dioxide-rich offgas for control of carbon monoxide and hydrocarbon emissions, or sale of the offgas as byproduct; direct discharge to the atmosphere is not being proposed. Also, at least one non-Lurgi coal gasification plant currently under construction, the Tennessee Eastman Kingsport, Tennessee Texaco gasification project, proposes catalytic incineration of the carbon monoxide enriched portion of the carbon dioxide offgas for control of carbon monoxide emissions (21).

Publicly available characterization data for the methanol/water distillation bottoms are extremely limited. This is apparently due to the fact that the size of the still bottoms stream is generally quite small relative to other wastewater streams requiring similar wastewater treatment (e.g., gas liquor and synthesis condensates). Thus, from an operational standpoint, the still bottoms are likely to be of minor significance other than for checking still operation and methanol losses. One set of data, provided by SASOL personnel (19), are presented in Table B-4. At the SASOL facility, this waste stream is sent directly to biological treatment where it comprises less than 2% of the feed to this system.

TABLE B-4. CHARACTERIZATION DATA FOR METHANOL/WATER DISTILLATION BOTTOMS AT SASOL (19)

Parameter/Component	Value
pH	9.7
Phenol, mg/L	18
Cyanides (as CN), mg/L	10.4 (includes thiocyanate)
Ammonia (as N), mg/L	42
Sulfides (as S)	Trace
COD, mg/L	1,686

B.5 PROCESS RELIABILITY

The original Lurgi nonselective Rectisol unit built at SASOL in 1955 has operated with an on-stream factor of about 97% (17). Normal maintenance includes partial shutdowns about once per year for cleaning of critical equipment, and complete shutdown every two years during the normal plant downtime. Major upsets in the Rectisol unit requiring process adjustments rarely occur (19).

As discussed in Section B.2, plugging problems in a two-stage selective Rectisol unit at a coal gasification facility have been reported (16). This problem has been attributed to deposition of elemental sulfur resulting from the presence of oxygen and nitrogen oxides in the Rectisol feed gas. Fouling was at least partially controlled by allowing low levels of hydrogen cyanide and ammonia to enter the Rectisol unit to solubilize sulfur by formation of ammonium thiocyanate. A more fundamental solution is the hydrogenation of nitrogen oxides and oxygen over a cobalt molybdate catelyst ahead of the Rectisol unit. Detailed operating data from this facility are not available.

B.6 PROCESS ECONOMICS

Available capital costs and utility requirements for the Rectisol process are summarized in Tables B-5 and B-6, respectively. Tabulated capital costs are primarily conceptual design cost estimates while tabulated utility requirements are published data for existing units. It should be noted that the cost of a Rectisol unit is influenced by a variety of considerations including the feed gas flow rate, pressure, acid gas content, and heavy hydrocarbon content, and the desired levels of selectivity and product purity. Due to the number of variables and associated interdependencies of these variables which influence cost, costs of Rectisol systems tend to be highly case specific.

TABLE B-5. CAPITAL COSTS FOR RECTISOL ACID GAS REMOVAL UNITS

	Dry Feed Gas, kmol/hr	Total Pressure, MPa	CO_2, vol %	H_2S, vol %	Capital Cost, $\$10^6$ (adj. to 1980 basis)	Reference
Selective	6,100	7.8	35	0.25	13.5[a]	24
	96,384	2.9	28.9	0.25	150.6[b]	25
Nonselective	52,786	2.8	31.4	0.135	91.8[c]	23
	57,574	2.8	34.2	0.13	81.9[c]	22

[a] The feed gas to this unit does not contain heavy hydrocarbons. Cost includes refrigeration unit, erection, and plant startup. This is the same unit which is identified as Plant 5 in Table B-6.

[b] Data are based upon a conceptual design cost estimate. Details of the cost estimate are not available. The feed gas to this unit does not contain heavy hydrocarbons.

[c] Data are based upon a conceptual design cost estimate. The feed gas to this unit contains heavy hydrocarbons. Reported cost includes naphtha and methanol recovery and erection. It is not specified whether the costs for a refrigeration unit and unit startup are included.

TABLE B-6. UTILITY REQUIREMENTS FOR RECTISOL ACID GAS REMOVAL UNITS

	Selective Rectisol[a]					Non-Selective Rectisol[b]
	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6
Flow Rate, kmol/hr	3692-3992	6112	7112	6350	6100	16993
Pressure, MPa	3.2-3.3	7.3	3.0	3.3	7.8	2.6
Electric Power, kWh/kmol	0.14-0.15	0.31	0.18	0.57	0.168	No data
Low Pressure Steam, MJ/kmol	5.14-5.54	3.44	4.16	5.09	0.168	No data
Cooling Water, MJ/kmol	1.20-1.42	6.43	1.92	9.52	2.77	3.27
Stripping Nitrogen, kmol/kmol	0.067-0.072	0.031	0.048	0.067	1.91	0.682
Makeup Methanol, kg/kmol	0.0085-0.0092	0.0057	0.012	0.0079	0.043	No data
Refrigeration, MJ/kmol (at 227 to 235 K)	2.09-2.29	Included above in power and cooling water	1.90	Included above in power and cooling water	0.007	0.013

[a] Plant 1 is a refinery producing hydrogen by partial oxidation of oil; shift conversion occurs prior to acid gas removal (2,6). Refer to Table B-1 for performance data.
Plant 2 produces ammonia synthesis gas from crude hydrogen generated by partial oxidation; shift conversion occurs prior to acid gas removal (3). Utility requirements reflect the use of compression refrigeration. Refer to Table B-1 for performance data.
Plant 3 produces ammonia synthesis gas by coal gasification; shift conversion follows hydrogen sulfide removal but precedes carbon dioxide removal (2,6). After sulfur removal the gas is increased from 3 MPa to 5 MPa by compression; the additional power required for compression is not included in the tabulated electric power requirement. Tabulated data are based on gas flow rate after shift conversion. Refer to Figure B-3 for process flow diagram, and to Table B-1 for performance data.
Plant 4 uses a Rectisol unit for purification of hydrogen from partial oxidation of heavy crude oil; shift conversion occurs prior to acid gas removal (3).
Plant 5 produces ammonia synthesis gas by partial oxidation of oil; shift conversion occurs prior to acid gas removal. Approximately 62% of the incoming carbon dioxide is provided as a carbon dioxide fraction containing less than 1.5 ppmv sulfur for urea production (24).

[b] Plant 6 is the SASOL coal gasification facility (17). Refer to Figure B-5 for process flow diagram, and Table B-3 for performance data.

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APPENDIX C

COSTING METHODOLOGY AND BASE PLANT COSTS

APPENDIX C

COSTING METHODOLOGY AND BASE PLANT COSTS

In order to provide an indication of the economic impact of pollution controls, capital investment and total annualized cost estimates were developed for uncontrolled Lurgi-based facilities and applicable pollution control processes. These estimates are based primarily on factored estimates of costs contained in nonproprietary published literature. As such, they should be viewed only as general indicators of expected costs and should not be construed as definitive cost estimates for a specific plant. All costs have been updated to a first quarter 1980 dollar basis using generally accepted cost indexes such as the Chemical Engineering (CE) plant index.

The same methodology was used to develop capital and total annualized cost estimates for the base plants and pollution controls. Details of these methodologies are presented in Sections C.1 and C.2, respectively. The bases for the base plant cost estimates are presented in Section C.3. Bases for the pollution control cost estimates are presented in the PCTM Pollution Control Technology Appendices for Pollution Control Technical Manuals.

There are three general factors that lead to uncertainties in the cost estimates developed for this PCTM. These are related to the assumptions used to develop material and energy balances, the level of accuracy of the published cost data used, and the general methodology used to apply the acquired cost data to the processes addressed in this document.

Material and energy balances were derived mainly from 1) commercial synfuels tests and synfuels pilot plant studies, 2) data from analog industries, and 3) engineering calculations, as described in Section 3 and Appendices A and B. The level of accuracy in specifying the flow rates and quality of input streams to controls will affect the accuracy of the resulting pollution control cost estimates.

Sources of cost data used in this document are published costs for processes applied to similar streams in related industries, costs from published design studies for coal gasification plants, and vendor quotes. The accuracy of cost data taken from published sources is influenced by the details of the design upon which the cost was based and the cost methodology used. In addition, the accuracy of the published estimates and definition of the components included in these estimates (e.g., contingency reserves, working capital, land) are not always specified in the reference. Thus, extrapolation of published costs will introduce uncertainties in the resulting estimates.

The general costing methodology used in this manual (described in this appendix) also introduces some uncertainties. Other estimators may choose to use different factors for components such as direct and indirect installation costs and interest during construction. In addition, available cost estimates were adjusted to a 1st quarter 1980 basis using chemical process construction escalation indices. It is therefore possible that recent advances in the state-of-the-art are not reflected in some of the resulting cost estimates.

As a result of the above influences, the accuracy of the cost information presented will vary. However, the cost information presented is believed to be adequate for the use intended.

C.1 CAPITAL COSTS ESTIMATING METHODOLOGY

Capital costs presented in the Lurgi-based PCTM are total depreciable investments (TDI). TDI includes:

1) purchased and delivered equipment costs;
2) labor and materials costs to install the equipment;
3) indirect installation charges; such as
   - engineering and construction costs,
   - contractor fees, and
   - project and process contingency reserves, and
4) interest expenses on capital spent prior to start of operation (interest during construction)

It should be noted that the total depreciable investments presented do not include startup costs. This item could be a significant additional cost for new technologies such as those examined in this PCTM.

A variety of methods can be used to estimate the above cost items, although many methods utilize a factored approach. In factored cost estimates, the costs of purchased and delivered equipment is obtained from vendor quotes or estimated from previous projects using similar equipment. The remaining cost items are then estimated using a "factor" times the purchased and delivered equipment costs or other subsequently derived subtotal. These factors are generally derived based on historical trends.

For the cost estimates developed for this PCTM, the major source of cost information was the open literature although some vendor quotes were used. In general, literature cost information is not reported as purchased and delivered equipment costs. Some published data are installed equipment costs (purchased equipment plus direct installation costs), some also include one or more of the indirect installation charges listed previously, some are TDI estimates, and others are total capital requirements (TDI plus working capital and land costs).

In order to provide consistency in the various capital cost estimates developed for the PCTM, a capital cost methodology was developed. The methodology (and cost factors) used are summarized in Table C-1. Most cost data obtained from the literature were installed equipment costs (IEC). As indicated in the table, indirect installation charges were estimated as 48% of the IEC. Adding the indirect installation charges to the IEC yields the total plant (or process) costs. Interest during construction was estimated as 22.6% of the total plant costs. Summing these two terms gave the TDI.

The methodology and factors shown in Table C-1 also allowed TDI estimates to be made when costs other than IEC were reported in the literature. As an example, assume literature data equivalent to the total plant cost item listed in Table C-1, but not including contingency, were available. To estimate contingency costs, the reported data would first be adjusted back to IEC by dividing by 1.28. Total plant costs (as used in the PCTM) would then be estimated by multiplying the calculated IEC by 1.48. This value would then be multiplied by 1.226 to get TDI.

The factors indicated in Table C-1 were selected based on an evaluation of a variety of cost factors reported in the open literature (1,2,3,4). The factor for interest during construction is based on an assumed average spending period of 1.88 years (5) and an interest rate of 12 percent.

TABLE C-1. CAPITAL COST ESTIMATING METHOD

- Installed Equipment Costs (IEC)
- Indirect Installation Costs (IIC)
    - Engineering and Construction (25% of IEC)
    - Fees (3% of IEC)
    - Contingency (20% of IEC)
- Total Plant Costs (IEC + IIC = TPC)
- Interest During Construction (IDC) (22.6% of TPC)
- Total Depreciable Investment (TPC + IDC = TDI)[a]
- Working Capital (WC) (value of sixty days of coal)
- Land
- Total Capital Requirement (TDI + WC + Land)

[a] Value used throughout PCTM as capital cost.

C.2 ANNUALIZED COST ESTIMATING METHODOLOGY

Annualized costs consist of annual operating expenses plus annualized capital-related charges. Annual operating expenses include costs for labor (operating, supervision, and maintenance labor), raw materials, chemicals, catalysts, utilities (steam, electricity, cooling water, etc.), and overhead. Capital-related charges include interest on working capital, local taxes, insurance, depreciation, income taxes, and return-on-investment. The unit costs or factors used to estimate total annualized costs in this PCTM are listed in Table C-2.

All of terms listed in Table C-2, except capital recovery, are expressed in first year costs, i.e., in constant first quarter 1980 dollars. The capital recovery term, however, is a levelized value calculated using present worth and levelized cost procedures and the economic assumptions listed in Table C-3.

C.3 BASE PLANT COSTS

Capital and total annualized cost estimates were developed for the base plants examined. Base plant in this PCTM refers to a Lurgi-based synfuel plant with full production capabilities but without pollution control devices. The cost estimates were developed from information found in the open literature, adjusted to the bases used in this PCTM. Specifically, the literature data were 1) adjusted to delete the cost of pollution controls (to the extent those costs could be identified), 2) scaled to the plant capacities examined in the PCTM, and 3) adjusted to reflect first quarter 1980 dollars.

TABLE C-2. UNIT COSTS AND FACTORS FOR ANNUALIZED COST ESTIMATES

Operating Labor ($11/hr)
Supervision (15% of operating labor)
Maintenance (2% of total depreciable investment)
Maintenance Supervision (5% of maintenance)
Raw Materials
- Coal
  - Rosebud ($13.86/Mg)
  - Illinois No. 6 ($35.44/Mg)
  - Dunn County Lignite ($14.70/Mg)
- Water (\$0.036/m^3)

Utilities
- Steam ($3.70 to $8.20/Mg depending on quality)
- Electricity ($0.033/kW-hr)
- Fuel gas ($1.79/GJ)
- Cooling water (\$0.08/m^3)
- Boiler feed water (\$0.264/m^3)

Chemicals and Catalysts
Overhead Charges
- Plant overhead (50% of operating labor)
- General and administrative overhead (15% of operating labor and maintenance)

Laboratory Charges (5% of operating labor)
Byproduct Credits
- Ammonia ($140/Mg)
- Phenols ($22.20/Mg)

Capital-Related Charges
- Interest on working capital (12% of working capital)
- Local taxes and insurance (3.5% of total depreciable investment)
- Capital recovery (including income taxes, depreciation, and return-on-investment) (13.7% of total depreciable investment)

TOTAL ANNUALIZED COSTS (summation of above items)

All units costs are on a first quarter 1980 basis.

TABLE C-3. ASSUMPTIONS USED TO CALCULATE CAPITAL RECOVERY FACTOR

Financing basis :	100% equity
Desired after tax return on investment :	12% of total depreciable investment (TDI)
Income tax rate :	48% of taxable income
Economic facility life :	20 years
Facility life for depreciation purposes :	16 years
Depreciation method :	sum-of-the-years-digits
Investment tax credit :	20% of TDI

C.3.1 Base Plant Capital Costs

The major source of cost data for the Lurgi-based methanol, Mobil M-gasoline, and Fischer-Tropsch plants is an engineering study performed by the Mobil Research and Development Corporation (6). The plant capacities examined in this manual are approximately 35 percent of the capacities examined in this report. After the identifiable pollution control costs were substracted from the installed equipment costs (IEC) reported in Reference 6, the IECs were adjusted to the PCTM capacities by multiplying by 0.432. This factor equals 0.35 raised to the 0.8 power.

The resulting adjusted installed equipment costs were then converted into total depreciable investment (TDI) costs using the methodology outline earlier in Section C.1 of this appendix. Finally, the TDI costs were escalated to first quarter 1980 dollars using chemical engineering plant indices.

The Mobil report did not address the production of SNG as the only plant product. In order to estimate capital costs for SNG plants, estimates from the Mobil report for the nonsynthesis-related parts of the plant were combined with estimates for SNG production equipment from a separate engineering study (7). These combined values were then subjected to the same methodology described above for the non-SNG plants. Table C-4 summarizes the calculational steps used to estimate the base plant TDIs.

C.3.2 Base Plant Annualized Costs

Annual operating expenses and capital-related annualized charges were calculated for the base plant using the methodology and factors presented in Section C.2. Required inputs for that methodology are operating labor requirements, coal and raw water usage, chemical and catalyst requirements, an estimate of working capital, and total depreciable investment. Operating

TABLE C-4. BASE PLANT CAPITAL COST ESTIMATES

	Methanol	Mobil	F-T	SNG
Installed equipment costs (IEC)[a]	990.9	1083.9	1186.1	
IEC minus Pollution control costs[a]	847	940	1012.2	b
Scaled to PCTM capacity[c]	365.9	1406.1	437.3	360.2
Total depreciable investment (TDI) (10/77 $)[d]	663.7	736.6	793.2	653.4
TDI (1980 $)[e,f]	821.6	912.0	982.1	808.8

[a] Reference 6.

[b] Based on methanol synthesis plant minus methanol synthesis and SNG coproduction units (from Reference 6) plus SNG production costs from Reference 7.

[c] Scaling factor used (0.432) was ratio of plant capacities raised to the 0.8 power.

[d] TDI was calculated by multiplying installed equipment costs, as adjusted, by 1.81.

[e] Factor used to escalate 10/77 costs to first quarter 1980 dollars was 1.24.

[f] Original cost data were for gasifying a subbituminous coal. Cost estimates developed from these data were assumed to be approximately true for other coals also.

All costs are millions of dollars.

labor and chemicals and catalysts costs were based on values given in the Mobil report (6). Raw water usage was assumed to be approximately 7600 m^3/day in all instances and had negligible impact on the annualized cost estimates. Coal usage was obtained from material flows developed for the base plants (see Appendix E). Working capital was estimated as equal to the cost of 60 days of coal. A 90 percent annual operating factor was assumed in developing the annualized cost estimates. Table C-5 summarizes the inputs used to develop the base plant annualized costs, while Table C-6 summarizes the annualized costs developed.

TABLE C-5. INUPTS USED TO ESTIMATE BASE PLANT ANNUALIZED COSTS

	Methanol	Mobil	F-T	SNG
Operating Labor,[a] people	128	139	206	128
Raw Water, m^3/day	7,600	7,600	7,600	7,600
Coal, Mg/day				
Rosebud	7,110	7,110	7,110	7,110
Illinois No. 6	5,800	5,800	5,800	5,800
Lignite	9,590	9,590	9,590	9,590
Chemicals and Catalysts,[a] 10^6\$/yr	1.6	1.8	1.3	1.6
Working Capital,[b] 10^6\$				
Rosebud coal cases	5.4	5.4	5.4	5.4
Illinois No. 6 coal cases	11.4	11.4	11.4	11.4
Lignite cases	7.7	7.7	7.7	7.7
Total depreciable investment, 10^6\$	822	912	982	809

[a] From data in Reference 6.

[b] Based on value of 60 days of coal.

All costs are first quarter 1980 dollars.

TABLE C-6. BASE PLANT ANNUALIZED COST ESTIMATES

Type of Synfuel Facility	Total Annualized Costs, 10^6 \$/yr		
	Subbituminous Coal (Montana Rosebud)	Bituminous Coal (Illinois No. 6)	Lignite (Dunn County, ND)
SNG	199	235	213
Methanol	201	238	215
Mobil M	220	256	234
Fischer-Tropsch	236	272	250

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APPENDIX D

THE FATE OF TRACE ELEMENTS IN LURGI GASIFICATION SYSTEMS

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Coals, like other sedimentary rocks, contain small amounts of a wide variety of elements derived from both the parent organic material and from inorganic minerals codeposited with or subsequently introduced in the original organic matrix. When coal is gasified, volatile elements such as Se, Hg, and the halogens are partially or totally converted to gaseous compounds. Nonvolatile elements (e.g., Cd, Zn) may also be present in raw gases as compounds of entrained dust or organic aerosols. Cooling and wet scrubbing of raw gases results in the condensation or physical removal of most of the trace element loading. From an environmental standpoint, trace elements are of concern when they leave the Lurgi system as potentially mobil or bioavailable constituents of waste streams. The primary streams which are of concern are 1) cooled synthesis gases and Rectisol acid gases, 2) gas liquors, 3) Lurgi ash leachates, and 4) flue gases and/or wastes from combustion of (or alternate processing of) byproduct tars and oils.

There is currently a modest body of data upon which material balances around Lurgi gasification systems for specific elements can be based. This data is based upon gasification tests for several American and foreign coals:

- Dunn/Mercer County (N.D.) lignite at Sasol (1,2),
- Rosebud (Montana) subbituminous coal at Westfield (3),
- Illinois No. 5 and No. 6 coals at Westfield (4),
- South African coal at Sasol (5), and
- Yugoslavian lignite at Kosovo (6).

Reports from several of these tests (Dunn/Mercer County, Sasol, and Kosovo) include trace element and flow rate data for all of the major feed and waste streams, allowing mass balance calculations to be made. The Illinois Nos. 5 and 6 reports include data only for the feed coal and ash, while the Rosebud report includes data for the feed coal, ash, and liquor streams. The Rosebud report presents two sets of analyses of the coal and ash streams, which for most elements were considerably different. Sets of values that constituted the worst case for each element in terms of percent found in the ash were chosen for determining the estimated distributions.

Tables D-1 through D-7 summarize, for each of the seven coals tested, the concentrations of twenty elements of environmental concern in the input coal, the concentration and percent of the input element in the ash, oil, tar, and liquor streams, and the total percentage recovery. Table D-8 summarizes the minimum and maximum concentrations found in each stream, while Table D-9 lists the minimum and maximum percent recoveries in each stream. Few trends are evident from this data, primarily due to limitations in the sampling and analysis of the various streams and the lack of complete sets of data for the Illinois Nos. 5 and 6, Rosebud, and Mercer County test reports.

Table D-10 summarizes ash leaching data for various coals expressed as microgram trace element leached per gram ash. It is important to note that the various leaching studies used different leaching conditions. Leaching studies are influenced by four principal variables: 1) the duration of the leaching period, 2) the type of system used (e.g., batch or flow through columns), 3) the liquid to solid ratio, and 4) the experimental parameters controlled (e.g., temperature, pH, and aerobic or anaerobic conditions).

Yu subjected ashes from the gasifications of Rosebud, Illinois No. 5, and Illinois No. 6 coals in the Westfield Lurgi gasification facility to the RCRA Extraction Procedure (7). The RCRA Extraction Procedure is designed to roughly approximate the extraction of soluble material with rainwater. The solid is extracted with a sixteen-fold excess of leaching solution at a pH of 5.0 for a 24-hour time period at room temperature. Following the extraction period, the sample is diluted to an aqueous volume of 20 times the sample weight and then filtered to separate the liquid and solid phases. The extract is then analyzed for 8 metals and other constituents which are listed in the Extraction Procedure.

Shriner performed two different types of leaching tests on the ash resulting from gasification of Rosebud, Illinois No. 5, and Illinois No. 6 coals in the Westfield Lurgi gasifier (8). Batch leaching tests attempted to simulate the conditions of natural flooding and thus the maximum dissolution of soluble constituents. Column leaching tests attempted to simulate the movement of rainwater percolate through a landfill. In the batch leaching tests, 25 g of ash and 250 ml of deionized water (pH 5.55) were shaken for 24 hours, decanted, filtered, shaken again for 24 hours, and filtered. In the column leaching tests, approximately 40 g of air-dried, unsieved Lurgi waste were added to glass tubes 7.5 cm in diameter and 46 cm long. Leachate quantities of approximately 80 ml, 80 ml, and 160 ml were collected for Rosebud, Illinois No. 5, and Illinois No. 6 gasifier ash, respectively, under falling head conditions at flow rates of 0.5 to 2.0 ml of deionized water per minute.

Griffin studied the leaching characteristics of ash obtained from the gasification of Rosebud, Illinois No. 5, and Illinois No. 6 coals in the Westfield Lurgi gasifier (9). Leachates were generated at 4 pH levels and under two different gas atmospheres. Large-volume, static leaching tests were used. The ash was initially ground to 28 mesh. Slurries of 1 part ash and 10 parts distilled water were placed in 2-1/2 and 5-gallon glass carboys. Over a period of 3 to 6 months the slurries were stirred daily and their pH monitored or readjusted when necessary to a specified value.

Somerville reported leaching characteristics of ash obtained from the gasification of Mercer County coal in the Lurgi Gasifier at SASOL (10). The leaching procedure attempted to maximize the quantity of the element leached. Ten grams of finely ground ash were added to 50 ml of deionized water (pH 5.55) and refluxed at the boiling point of deionized water for 16 to 24 hours.

TABLE D-1. CONCENTRATION AND DISTRIBUTION OF TRACE ELEMENTS - DUNN COUNTY LIGNITE (1)

Element	Coal, ppm	Ash		Oil		Tar		Liquor		Total, %
		ppm	%	ppm	%	ppm	%	ppm	%	
As	8	74	102	24	3.7	7	4.9	0.10	1.9	112
B	56	1680	330	4	0.087	1	0.10	0.90	2.4	333
Be	0.27	6	244			<0.10	<2.1			<247
Cd	<1	0.50	>5.5	0.50	>0.61	<0.30	<1.7	<0.20	<30.1	<38
Co	1.2	13	119	0.90	0.91	0.60	2.8	0.0010	0.13	123
Cr	5.3	140	291	4	0.92	5	5.3	0.020	0.57	297
Cu	10.6	27	28	2	0.23	3	1.6	0.010	0.14	30
F	29.3	191	71.7	5	0.21	51	9.8	5	25.7	107
Hg	0.20	0.055	3	0.16	0.98	2.9	81.6	0.17	128	213
Mn	70.7	760	118	0.70	0.012	11	0.88	0.030	0.064	119
Mo	4	12	33	6	1.8	2	2.8	0.040	1.5	39
Ni	6.7	25	41	2	0.36	3	2.5	0.0060	0.13	44
Pb	2.7	58	236	4	1.8	14	29.2	0.0050	0.28	268
Sb	0.27	4	163							163
Se	0.40	0.50	13.7	0.40	1.2	0.20	2.8	0.0040	1.5	19
Th	4	45	124			1	1.4			125
U	4	7	19.2			0.90	1.3			21
V	21.3	150	77.5	0.20	0.011	3	0.79	0.0010	0.0071	78
Zn	6.7	10	16.4	2	0.36	0.90	0.76	0.20	4.5	22
Zr	85.3	520	67.1	1	0.014	10	0.66	0.0080	0.014	68

Blanks = no data available.

TABLE D-2. CONCENTRATION AND DISTRIBUTION OF TRACE ELEMENTS – MERCER COUNTY LIGNITE AT SASOL (2)

	Coal	Ash		Oil		Tar		Liquor		Total
Element	ppm	ppm	%	ppm	%	ppm	%	ppm	%	%
As	30	60	13.1	1.7	0.030	2	0.21	3	9.8	23
B	300	>1500	>32.8	30	0.053	20	0.21	3	0.98	34
Be	2	5	16.4	0.050	0.013	0.10	0.16	0.0080	0.39	17
Cd	<0.10	<1	<65.7	<0.10	<0.53	<0.10	<3.1	<0.030	<29.5	<99
Co	2	10	32.8	0.020	0.0053	0.050	0.078	<0.030	<1.5	<34
Cr	6	40	43.8	0.60	0.053	1	0.52	<0.030	<0.49	<45
Cu	5	50	65.7	2	0.21	0.10	0.063	0.30	5.9	72
F	24	230	63	0.060	0.0013	12	1.6	0.50	2	67
Hg	0.050	< 0.10	<13.1	<0.10	<1.1	<0.10	<6.3	<0.030	<59	<80
Mn										
Mo	0.50	4	52.6	0.020	0.021	0.020	0.13	<0.20	<39.4	<92
Ni	3	25	54.7	1.5	0.26	10	10.4	<0.20	<6.6	<72
Pb	20	200	65.7	0.15	0.0040	1.5	0.23	0.20	0.98	67
Sb	0.10	1	65.7	<0.020	<0.11	<0.050	<1.6	<0.030	<29.5	<97
Se	1	1.5	9.9	<0.010	<0.0053	0.20	0.63	2	197	<207
Th	1	6	39.4	<1	<0.53	2	6.3			<46
U	1	6	39.4	<1	<0.53	5	15.6	<0.20	<19.7	<75
V	10	70	46	0.15	0.0080	0.050	0.016	0.0030	0.030	46
Zn	0.60	0.50	5.5	0.40	0.35	6	31.3	0.40	65.6	103
Zr										

Blanks = no data available.

TABLE D-3. CONCENTRATION AND DISTRIBUTION OF TRACE ELEMENTS - SOUTH AFRICAN COAL AT SASOL (5)

	Coal	Ash		Oil		Tar		Liquor		Total
Element	ppm	ppm	%	ppm	%	ppm	%	ppm	%	%
As	3.3	1.7	18.5	26.3	3.6	4.1	2	1.2	38.3	62
B	100	133	47.9	0.53	0.0024	50	0.82	3.3	3.5	52
Be	2.3	0.037	0.58	0.053	0.010	0.80	0.57	0.040	1.8	3
Cd	<0.10	<0.10	<36	0.27	>1.2	<0.040	<0.66	<0.030	<31.6	<69
Co										
Cr										
Cu										
F	100	150	54	<0.50	<0.0022	3.2	0.053	40	42.1	<96
Hg	<0.10	0.10	>36	0.12	<0.54	0.40	>6.6	<0.030	<31.6	<75
Mn	500	2000	144	0.27	0.00024	2.7	0.0089	1.5	0.32	144
Mo										
Ni	43.3	183	152	1.2	0.012	2.7	0.10	0.30	0.73	153
Pb	16.7	50	108	0.73	0.020	50	4.9	0.40	2.5	115
Sb	<0.50	<0.50	<36	0.53	>0.48	0.90	>3	0.15	>31.6	<71
Se										
Th										
U										
V	367	1000	98.1	0.23	2.8E-04	4.9	0.022	0.30	0.086	98
Zn										
Zr										

Blanks = no data available.

TABLE D-4. CONCENTRATION AND DISTRIBUTION OF TRACE ELEMENTS - ROSEBUD COAL AT WESTFIELD (3)

Element	Coal	Ash		Oil		Tar		Liquor		Total
	ppm	ppm	%	ppm	%	ppm	%	ppm	%	%
As	0.57	26	388					0.030	7.1	395
B	32	380	101					11.6	48.9	150
Be	0.71	2.8	33.5					0.48	91.3	125
Cd	0.31	2.4	65.8					0.22	95.8	162
Co	0.55	4.3	66.5							67
Cr	4.2	440	890					2.8	90	980
Cu	8.9	130	124					2.2	33.4	158
F	65	600	78.5					41.4	86	164
Hg	0.17	0.030	1.5					0.12	95.3	97
Mn	3.4	790	1975							1975
Mo	2.2	200	773							773
Ni	14	216	131					9.1	87.7	219
Pb	12	56	39.7					6	67.5	107
Sb	1.5	4.5	25.5					0.10	9	35
Se	0.33	2.2	56.7					0.11	45	102
Th										
U	0.88	13	126					0.29	44.5	170
V	14	91	55.2					5.5	53	108
Zn	8	48	51					4.4	74.2	125
Zr										

Blanks = no data available.

TABLE D-5. CONCENTRATION AND DISTRIBUTION OF TRACE ELEMENTS - ILLINOIS NO. 5 COAL AT WESTFIELD (4)

Element	Coal	Ash		Oil		Tar		Liquor		Total
	ppm	ppm	%	ppm	%	ppm	%	ppm	%	%
As	1.6	0.30	1.7							
B	307	673	20.2							2
Be	2.2	22	92							20
Cd	<0.30	<0.30	<9.2							92
Co	3.8	38	92							<9
Cr	15	592	363							92
Cu	10	273	251							363
F	55	4.6	0.77							251
Hg	0.17	0.016	0.87							1
Mn	21	338	148							1
Mo	7	8	10.5							148
Ni	32	462	133							11
Pb	30	219	67.2							133
Sb	0.30	0.30	9.2							67
Se										9
Th										
U										
V	21	181	79.3							
Zn	182	1580	79.9							79
Zr										80

Blanks = no data available.

TABLE D-6. CONCENTRATION AND DISTRIBUTION OF TRACE ELEMENTS - ILLINOIS NO. 6 COAL AT WESTFIELD (4)

Elem	Coal	Ash		Oil		Tar		Liquor		Total
	ppm	ppm	%	ppm	%	ppm	%	ppm	%	%
As	1	0.10	1							1
B	132	622	47.1							47
Be	1.5	13.4	89.3							89
Cd	<0.30	<0.30	<10							<10
Co	3.2	34	106							106
Cr	18.3	806	440							440
Cu	12	239	199							199
F	79	5.2	0.66							1
Hg	1	0.040	0.40							<1
Mn	20	243	121							121
Mo	7	6	8.6							9
Ni	14	456	326							326
Pb	12	96	80							80
Sb	0.10	0.20	20							20
Se	1.3									
Th										
U										
V	29	301	104							104
Zn	43	469	109							109
Zr										

Blanks = no data available.

TABLE D-7. CONCENTRATION AND DISTRIBUTION OF TRACE ELEMENTS - YUGOSLAVIAN LIGNITE AT KOSOVO (6)

Element	Coal	Ash		Oil		Tar		Liquor		Total
	ppm	ppm	%	ppm	%	ppm	%	ppm	%	%
As	59	75	21	1.9	0.05	18	0.7	0.1	0.1	22
B										
Be	1	2.5	43	NF	NF	0.1	0.2	NF	NF	43
Cd	4	69	297	0.075	0.03	0.7	0.4	0.0014	0.03	297
Co	3.4	17	85	0.19	0.09	NF	NF	NF	NF	85
Cr	87	180	35	3.9	0.07	3.2	0.09	0.023	0.02	17
Cu	43	40	16	1.1	0.04	17	0.9	0.011	0.02	17
F										
Hg	0.74	0.3	7	0.2	0.4	NF	NF	0.14	15	22
Mn										
Mo	6.4	8.9	24	0.18	0.05	NF	NF	NF	NF	24
Ni	150	320	36	NF	NF	9.5	0.2	0.013	0.01	36
Pb	8.2	52	108	1.4	0.3	7.2	2	0.014	0.1	110
Sb	NF	NF	NF	NF	NF	NF	NF	NF	NF	NF
Se	20	24	20	1.8	0.2	1.7	0.2	0.05	0.2	21
Th										
U										
V	14	100	123	NF	NF	0.53	0.09	NF	NF	123
Zn	140	2.1	0.3	15	0.2	30	0.5	0.28	0.2	1
Zr										

NF = Not found.
Blanks = No data available.

TABLE D-8. SUMMARY OF TRACE ELEMENT CONCENTRATIONS IN VARIOUS WASTE STREAMS FROM LURGI GASIFIERS FOR SEVEN AMERICAN & FOREIGN COALS (1,2,3,4,5,6)

	Coal PPM		Ash PPM		Oil PPM		Tar PPM		Liquor PPM	
Element	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
As	0.57	59	0.10	75	1.7	26.3	2	18	0.030	3
B	32	307	133	1680	0.53	30	1	50	0.90	11.6
Be	0.27	2.3	0.037	22	NF	0.053	<0.10	0.8	NF	0.48
Cd	<0.10	4	<0.10	69	0.075	0.50	<0.04	0.7	0.0014	0.22
Co	0.55	3.8	4.3	38	0.020	0.90	NF	0.6	NF	<0.030
Cr	4.2	87	40	806	0.60	4	1	5	0.020	2.8
Cu	5	43	27	273	1.1	2	0.10	17	0.010	2.2
F	24	100	4.6	600	0.060	5	3.2	51	0.50	41.4
Hg	0.050	1	0.016	0.3	<0.10	0.2	NF	2.9	<0.030	0.17
Mn	3.4	500	243	2000	0.27	0.70	2.7	11	0.030	1.5
Mo	050	7	4	200	0.020	6	NF	2	NF	<0.20
Ni	3	150	25	462	NF	2	2.7	10	0.0060	9.1
Pb	2.7	30	50	219	0.15	4	1.5	50	0.0050	6
Sb	NF	1.5	0.20	4.5	NF	0.53	NF	0.9	NF	0.15
Se	0.33	20	0.50	24	<0.010	1.8	0.20	1.7	0.0040	2
Th	1	4	6	45	<1	<1	1	2		
U	0.88	4	6	13	<1	<1	0.90	5	NF	0.29
V	10	367	70	1000	NF	0.23	0.050	4.9	0.0010	5.5
Zn	0.60	182	0.50	1580	0.40	15	0.90	30	0.20	4.4
Zr	85.3	85.3	520	520	1	1	10	10	0.0080	0.008

NF = Not found.
Blanks = no data available.

TABLE D-9. SUMMARY OF DISTRIBUTION OF TRACE ELEMENTS AMONG WASTE STREAMS FROM LURGI GASIFIERS FOR SEVEN AMERICAN & FOREIGN COALS (1,2,3,4,5,6)

Element	Coal PPM		Ash %		Oil %		Tar %		Liquor %		Total %	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
As	0.57	59	1	388	0.030	3.7	0.21	4.9	0.1	38.3	1	395
B	32	307	20.2	330	0.0024	0.087	0.10	0.82	0.98	48.9	20.2	333
Be	0.27	2.3	0.58	244	NF	0.013	0.16	2.1	NF	91.3	3	<247
Cd	<0.10	4	>5.5	297	0.030	>1.2	<0.66	<3.1	0.03	95.8	<9.2	307
Co	0.55	3.8	32.8	119	0.0053	0.91	NF	2.8	NF	<1.5	<34.2	123
Cr	4.2	87	35	890	0.053	0.92	0.09	5.3	0.02	90	39.9	980
Cu	5	43	16	251	0.040	0.23	0.063	1.6	0.02	33.4	30	251
F	24	100	0.66	78.5	0.0013	0.21	0.053	9.8	2	86	0.66	164
Hg	0.050	1	0.40	36	0.4	1.1	NF	81.6	15	128	0.40	213
Mn	3.4	500	118	1975	2.4E-04	0.012	0.0089	0.88	0.064	0.32	119	1975
Mo	0.50	7	8.6	773	0.021	1.8	NF	2.8	NF	<39.4	8.6	773
Ni	3	150	36	326	NF	0.36	0.10	10.4	0.01	87.7	<39.9	326
Pb	2.7	30	39.7	236	0.0040	1.8	0.23	29.2	0.1	67.5	66.9	268
Sb	NF	1.5	NF	163	NF	0.48	NF	3	NF	>31.6	9.2	163
Se	0.33	20	9.9	56.7	<0.0053	1.2	0.2	2.8	0.20	197	19.3	<207
Th	1	4	39.4	124	<0.53	0.53	1.4	6.3			<46.2	125
U	0.88	4	19.2	126	<0.53	0.53	1.3	15.6	<19.7	44.5	20.5	170
V	10	367	46	123	NF	0.011	0.016	0.79	NF	53.	46	<126
Zn	0.60	182	0.3	109	0.2	0.36	0.5	31.3	0.16	74.2	15.6	125
Zr	85.3	85.3	67.1	67.1	0.014	0.014	0.66	0.66	0.014	0.014	67.7	68

NF = Not found.
Blanks = no data available.

TABLE D-10. LEACHING CHARACTERISTICS OF LURGI ASH

Trace Element	Extractable Element Concentration, µg element per g ash												
	Rosebud				Illinois No. 5				Illinois No. 6				Mercer County
	A	B	C	D	A	B	C	D	A	B	C	D	E
Ag	<0.004				<0.008				<0.018				<0.005
As	<0.030	6.0	0.06	<10.0	0.11	<10.0	<0.066	6.0	0.42	<10.0	15.0		
B	18.0			512	8.0			100	1.7			55.0	183.1
Ba	16.6			<1.0	<8.6			<1.0	<4.0			<1.0	0.05
Be				0.8				0.5				0.3	
Cd	<0.011	0.006	0.001	0.6	0.88	0.024	0.124	1.3	0.22	0.48	0.054	0.6	
Co				2.0				2.7				1.9	0.10
Cr	<0.12			1.4	0.090			0.4	<0.058			1.2	0.35
Cu	0.092	3.0	0.04	5.4	0.11	0.9	0.52	3.0	<0.040	10.6	4.41	7.3	0.25
F				3.0				1.4				0.4	19.5
Hg	<0.008		0.0009	<0.002	<0.008		0.0001	<0.002	<0.008			<0.02	<0.005
Mn	90		0.517	265	17		5.1	90	6.8		3.64	38.0	0.03
Mo				<0.3				<3.0				<0.3	5.0
Ni	1.1		0.059	5.0	60.0		1.48	13.7	1.0		1.28	5.0	0.045
Pb	<0.011	0.08	0.24	4.0	0.036	0.13	0.32	2.0	0.026	0.64	0.402	2.0	0.035
Sb				13.0				7.0				6.0	0.048
Se	<0.020		0.13	<3.0	<0.026		0.19	<2.0	<0.05		0.097	<1.0	0.1
U	<10				<10				<10				
V													40.05
Zn	3.2	0.084	0.063	15.0	626	0.17	0.53	1100	76	27.2	4.26	170	0.1

A Denotes batch leaching data from Yu (7)
B Denotes batch leaching data from Shriner (8)
C Denotes column leaching data from Shriner (8)
D Denotes batch leaching data from Griffin (9)
E Denotes column leaching data from Somerville (10)
Blanks = no data available.

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APPENDIX E

MATERIAL BALANCES

TABLE E-1. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ROSEBUD COAL

	Stream No.	1	21	2	3	4	5	205
	Stream Name	Run-of-Mine Coal	Coal Fines	Prepared Coal	Steam	Oxygen	Raw Lurgi Gas	Low Pressure Coal Lockhopper Vent Gas
kg-moles/hr	Hydrogen						7,619	4.7
	Oxygen					2,270	39	0.024
	Nitrogen/Argon					137	162	0.10
	Carbon Monoxide						2,806	1.7
	Carbon Dioxide						5,733	3.5
	Methane						2,075	1.3
	Ethane						93	0.057
	Ethylene						13	0.008
	Propane						15	0.009
	Propylene						13	0.008
	Butane						7.4	0.005
	Butylene						13	0.008
	C5+ Aliphatics						8.6	0.005
	Benzene						9.7	0.006
	Toluene						2.3	0.001
	Other aromatics						1.9	0.001
	Hydrogen Sulfide						82	0.050
	Carbonyl Sulfide						1.1	0.0007
	Methyl Mercaptan						7.2	0.004
	Ethyl Mercaptan						2.3	0.001
	C3+ Mercaptans						0.3	0.0002
	Hydrogen Cyanide						1.2	0.0007
	Ammonia						137	0.084
	Hydrogen Chloride						0.4	0.0002
	Methanol							
	Total dry gas					2,407	18,843	11.6
kg/hr	Water	112,630	39,420	73,210	370,800		293,634	1.7
	Coal (MAF)	298,930	104,620	194,300				
	Ash	44,350	15,530	28,830				
	Particulates						495	0.052
	Organic Aerosols							1.9
	Tars						5,710	
	Oils						6,181	
	Phenols						1,371	
	Fatty Acids						604	
	Other Constituents						2,389	
	Total	455,910	159,570	296,340	370,800	77,460	709,664	247

[a] Assumes Lurgi gas is used as the lockhopper pressurant. Composition shown excludes ejection air.

TABLE E-1. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ROSEBUD COAL (Continued)

	Stream No.	239	403	206	209	111	112	
	Stream Name	Ash Quench Makeup Water	Quenched Ash	Ash Lock Vent Gas	Gas Liquor Depressurization Gas	Tar	Oil	
kg-moles/hr	Hydrogen							
	Oxygen			14.3				
	Nitrogen/Argon			0.9				
	Carbon Monoxide				1.1			
	Carbon Dioxide				80			
	Methane				3.6			
	Ethane				0.18			
	Ethylene				0.18			
	Propane							
	Propylene							
	Butane							
	Butylene							
	C5+ Aliphatics							
	Benzene							
	Toluene							
	Other aromatics							
	Hydrogen Sulfide				0.93			
	Carbonyl Sulfide				0.011			
	Methyl Mercaptan				0.34			
	Ethyl Mercaptan				0.2			
	C3+ Mercaptans				0.027			
	Hydrogen Cyanide				0.005			
	Ammonia				2.0			
	Hydrogen Chloride							
	Methanol							
	Total dry gas			15.2	88.6			
kg/hr	Water	13,600	7,700	1,550	85			
	Coal (MAF)		30,600					
	Ash							
	Particulates			3.5		426	12	
	Organic Aerosols							
	Tars					5,665		
	Oils						6,181	
	Phenols							
	Fatty Acids							
	Other Constituents							
	Total	13,600	38,300	2,043	3,830	6,091	6,193	

TABLE E-1. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ROSEBUD COAL (Continued)

	Stream No.	210	210S	10	10S	213	213S	
	Stream Name	Gas Liquor Synthesis Cases	Gas Liquor SNG Case	Quenched Lurgi Gas- Synthesis Cases	Quenched Lurgi Gas- SNG Case	AGR Offgases- Synthesis Cases	AGR Offgases- SNG Case	
kg-moles/hr	Hydrogen			7,619	8,280	23	25	
	Oxygen			39	39			
	Nitrogen/Argon			162	162	4	4	
	Carbon Monoxide			2,805	2,146	56	43	
	Carbon Dioxide	93.3	93.3	5,560	6,220	4,954	5,772	
	Methane			2,071	2,071	54	54	
	Ethane			93	93	53	53	
	Ethylene			13	13	7.5	7.5	
	Propane			15	15	15	15	
	Propylene			13	13	13	13	
	Butane			7.4	7.4	6.6	6.5	
	Butylene			13	13	11.5	11.5	
	C5+ Aliphatics			8.6	8.6	0.9	0.9	
	Benzene			9.7	9.7	0.53	0.61	
	Toluene			2.3	2.3	0.032	0.04	
	Other aromatics			1.9	1.9			
	Hydrogen Sulfide	0.50	0.50	81	81	80.9	80.9	
	Carbonyl Sulfide			1.1	0.79	1.1	0.79	
	Methyl Mercaptan			6.9	6.9	6.6	6.6	
	Ethyl Mercaptan			2.1	2.1	1.5	1.5	
	C3+ Mercaptans			0.3	0.27			
	Hydrogen Cyanide	0.056	0.056	1.1	0.73			
	Ammonia	135	135	0.2	0.56	0.54	0.36	
	Hydrogen Chloride			0.2	0.19	0.15	0.52	
	Methanol					8.1	8.4	
	Total dry gas			18,526	19,188	5,298	6,105	
kg/hr	Water	292,960	281,039	576	612			
	Coal (MAF)							
	Ash							
	Particulates	57	57					
	Organic Aerosols							
	Tars	45	45					
	Oils							
	Phenols	1,371	1,371					
	Fatty Acids	604	604					
	Other Constituents	2,389	2,389					
	Total	303,850	291,929	388,868	401,597	228,219	263,864	

TABLE E-1. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ROSEBUD COAL (Continued)

	Stream No.	216	216S	114	114S	12	12S	
	Stream Name	Methanol/Water Still Bottoms Synthesis Cases	Methanol/Water Still Bottoms SNG Case	By-Product Lurgi Naphtha Synthesis Cases	By-Product Lurgi Naphtha SNG Cases	Sulfur-Free Synthesis Gas Synthesis Cases	Sulfur-Free Synthesis Gas SNG Case	
kg-moles/hr	Hydrogen					7,596	8,255	
	Oxygen					39	39	
	Nitrogen/Argon					158	158	
	Carbon Monoxide					2,749	2,103	
	Carbon Dioxide					606	448	
	Methane					2,017	2,017	
	Ethane					40	40	
	Ethylene					5.5	5.5	
	Propane					0.1	0.09	
	Propylene							
	Butane			0.8	0.9			
	Butylene			1.5	1.5			
	C5+ Aliphatics			7.6	7.6			
	Benzene			9.2	9.1			
	Toluene			2.3	2.3			
	Other aromatics	0.004	0.004	1.9	1.9			
	Hydrogen Sulfide			0.1	0.1			
	Carbonyl Sulfide							
	Methyl Mercaptan			0.3	0.3			
	Ethyl Mercaptan			0.6	0.6			
	C3+ Mercaptans			0.27	0.27			
	Hydrogen Cyanide	0.007	0.007	0.55	0.37			
	Ammonia	0.044	0.045					
	Hydrogen Chloride	0.19	0.19					
	Methanol	0.017	0.018					
	Total dry gas	0.26	0.26	25.1	24.9	13,211	13,066	
kg/hr	Water	9,956	9,972					
	Total	9,965	9,973	1,876	1,872	158,451	135,516	

TABLE E-1. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ROSEBUD COAL (Continued)

	Stream No.	228S	236S	110S				
	Stream Name	Methanation Condensate SNG Synthesis	Dehydration Offgases SNG Synthesis	Product SNG SNG Synthesis				
kg-moles/hr	Hydrogen Oxygen Nitrogen/Argon Carbon Monoxide Carbon Dioxide Methane Total dry gas	 0.1 0.4 0.5		123.7 158 2.1 23.1 4,633.6 4,940.5				
kg/hr	Water Total	54,300 54,332	204 204	10 81,128				

TABLE E-1. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ROSEBUD COAL (Continued)

	Stream No.	117 ME	237 ME	18 ME	228 ME	231 ME	236 ME	110 ME
	Stream Name	Fuel Grade Methanol MeOH Synthesis	Methanol Wastewater MeOH Synthesis	Purge Gas to Methanation MeOH Synthesis	Methanation Condensate MeOH Synthesis	CO_2 Removal Offgas MeOH Synthesis	Dehydration Offgases MeOH Synthesis	Coproduct SNG MeOH Synthesis
kg-moles/hr	Hydrogen	0.04		1,608		0.1		80.5
	Oxygen							
	Nitrogen/Argon	0.01		158		0.14		158
	Carbon Monoxide	0.03		190		0.001		0.95
	Carbon Dioxide	5.7		310	0.05	69.6		3.2
	Methane	1.1		2,016	0.2	2.4		2,521
	Ethane	0.25		39.7				
	Ethylene			5.5				
	Methanol	2,796	1.6	41.9				
	Ethanol	0.92	0.0004	0.009				
	Propanol	0.01	0.57	0.0007				
	Acetone	1.6		0.88				
kg/hr	Water	88	5,202	10	20,180	78	329	4
	Total	90,080	5,289	61,680	20,185	3,180	329	46,198

TABLE E-1. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ROSEBUD COAL (Continued)

	Stream No.	18 MM	107 MM	225 MM	226 MM	228 MM	231 MM	236 MM
	Stream Name	Purge & Expansion Gas to Methanation Mobil M Case	Crude Methanol Mobil M Case	Mobil M Wastewater	Fractionation Offgas to CO_2 Removal Mobil M	Methanation Condensate Mobil M	CO_2 Removal Offgas Mobil M	Dehydration Offgases Mobil M
kg-moles/hr	Hydrogen	1.608	0.05		0.7		0.1	
	Oxygen							
	Nitrogen/Argon	158	0.02		0.01		0.15	
	Carbon Monoxide	190	0.03	0.02	0.3		0.001	
	Carbon Dioxide	310	6.7	1.2	6.3	0.05	75.8	
	Methane	2,016	1.3		19	0.16	2.6	
	Ethane	40	0.3		5.3		0.005	
	Ethylene	5.5			0.5		0.0005	
	Propane				2.0			
	Propylene				0.1			
	Butane				1.5			
	Butylene				0.1			
	C5+ Aliphatics				0.4			
	Methanol	41.9	2.799	0.6				
	Ethanol	0.009	0.9					
	Propanol	0.0007	0.6					
	Acetone	0.88	1.6	3.6				
	Organic Acids			4.8				
	Total dry gas	4.370			36			
kg/hr	Water	10	5,298	55,450	35	20,180	85	332
	Total	61,680	95,430	55,990	1,022	20,185	3,458	332

TABLE E-1. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ROSEBUD COAL (Continued)

	Stream No.	110 MM	108 MM	109 MM	109 MM			
	Stream Name	Co-product SNG Mobil M	Blended Gasoline Mobil M	C_3 LPG Mobil M	C_4 LPG Mobil M			
kg-moles/hr	Hydrogen	81						
	Oxygen							
	Nitrogen/Argon	158						
	Carbon Monoxide	1.3						
	Carbon Dioxide	3.3						
	Methane	2,539						
	Ethane	5.3						
	Ethylene	0.5						
	Propane	2.0						
	Propylene	0.1						
	Butane	1.5						
	Butylene	0.1						
	C5+ Aliphatics	0.4						
	Total dry gas	2,793						
kg/hr	Water	4						
	Total	45,817	32,510	1,756	2,792			

TABLE E-1. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ROSEBUD COAL (Continued)

	Stream No.	14 FT	219 FT	220 FT	228 FT	238 FT	231 FT	236 FT
	Stream Name	Purge Gas to Methanation F-T Case	Wastewater From Alcohol Recovery F-T Case	Fractionation Offgases to CO_2 Removal	Methanation Condensate F-T Case	Wastewater From CO_2 Removal F-T Case	CO_2 Removal Offgas F-T Case	Dehydration Offgas F-T Case
kg-moles/hr	Hydrogen	1,363		8.2			0.3	
	Nitrogen/Argon	155		2.6			0.4	
	Carbon Monoxide	84		1.6			0.006	
	Carbon Dioxide	310		160	0.04		219	
	Methane	2,129		161	0.14		7.8	
	Ethane	53		68			0.2	
	Ethylene	30		31			0.08	
	Propane			2.9			0.008	
	Propylene			30			0.08	
	Butane			0.006				
	Butylene			0.04				
	Pentane			0.002				
	Pentene			0.006				
	C7+ Aliphatics	0.8		0.1				
	Acetone		13.6					
	Total dry gas	4,126		466			228	
kg/hr	Water		75,900	332	18,300	358	247	375
	Total	59,760	76,720	14,390	18,304	358	10,040	375

TABLE E-1. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ROSEBUD COAL (Continued)

	Stream No.	110 FT	100 FT	101 FT	102 FT	105 FT	106 FT	106 FT
	Stream Name	Co-product SNG F-T Case	Blended Gasoline F-T Case	Diesel Oil F-T Case	Heavy Fuel Oil F-T Case	Mixed Alcohols F-T Case	C_3 LPG F-T Case	C_4 LPG F-T Case
kg-moles/hr	Hydrogen	89						
	Nitrogen/Argon	157						
	Carbon Monoxide	2						
	Carbon Dioxide	14						
	Methane	2,766						
	Ethane	68						
	Ethylene	31						
	Propane	3						
	Propylene	30						
	Butane	0.006						
	Butylene	0.04						
	Pentane	0.002						
	Pentene	0.006						
	C7+ Aliphatics	0.1						
	Total dry gas	3,160						
kg/hr	Water	5						
	Total	53,930	19,660	3,986	1,167	3,380	1,284	195

TABLE E-2. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ILLINOIS NO. 6 COAL

	Stream No.	1	21	2	3	4	5	205[a]
	Stream Name	Run-of-Mine Coal	Coal Fines	Prepared Coal	Steam	Oxygen	Raw Lurgi Gas	Low Pressure Coal Lockhopper Vent Gas
kg-moles/hr	Hydrogen						7,455	3.5
	Oxygen					3,430	21	0.01
	Nitrogen/Argon					208	238	0.11
	Carbon Monoxide						3,419	1.6
	Carbon Dioxide						6,272	3.0
	Methane						1,874	0.9
	Ethane						98.4	0.047
	Ethylene						14.4	0.007
	Propane						16	0.008
	Propylene						14	0.007
	Butane						7.8	0.004
	Butylene						14	0.007
	C5+ Aliphatics						3.7	0.002
	Benzene						16	0.008
	Toluene						3.6	0.002
	Other aromatics						2	0.001
	Hydrogen Sulfide						181	0.086
	Carbonyl Sulfide						2.2	0.001
	Methyl Mercaptan						15.7	0.007
	Ethyl Mercaptan						5.2	0.002
	C3+ Mercaptans						0.67	0.0003
	Hydrogen Cyanide						1.2	0.001
	Ammonia						146.7	0.07
	Hydrogen Chloride						1.6	0.001
	Methanol							
	Total dry gas					3,638	19,824	9.4
kg/hr	Water	35,830	11,110	24,720	607,070		497,621	1.4
	Coal (MAF)	282,570	87,600	194,970				
	Ash	31,890	9,880	22,010				
	Particulates						579	0.042
	Organic Aerosols							1.5
	Tars						7,427	
	Oils						696	
	Phenols						1,152	
	Fatty Acids						192	
	Other Constituents						1,480	
	Total	350,290	108,590	241,700	607,070	117,040	952,630	213

[a] Assumes Lurgi gas is used as the lockhopper pressurant. Composition shown excludes ejection air.

TABLE E-2. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ILLINOIS NO. 6 COAL (Continued)

	Stream No.	239	403	206	209	111	112	
	Stream Name	Ash Quench Makeup Water	Quenched Ash	Ash Lock Vent Gas	Gas Liquor Depressurization Gas	Tar	Oil	
kg-moles/hr	Hydrogen							
	Oxygen			10.5				
	Nitrogen/Argon			0.6				
	Carbon Monoxide				2.2			
	Carbon Dioxide				164			
	Methane				7.3			
	Ethane				0.37			
	Ethylene				0.37			
	Propane							
	Propylene							
	Butane							
	Butylene							
	C5+ Aliphatics							
	Benzene							
	Toluene							
	Other aromatics							
	Hydrogen Sulfide				1.9			
	Carbonyl Sulfide				0.023			
	Methyl Mercaptan				0.69			
	Ethyl Mercaptan				0.49			
	C3+ Mercaptans				0.063			
	Hydrogen Cyanide				0.01			
	Ammonia				4.1			
	Hydrogen Chloride							
	Methanol							
	Total dry gas			11.1	182			
kg/hr	Water	9,900	5,300	1,132	169			
	Coal (MAF)							
	Ash		22,300					
	Particulates			2.6		540	1.4	
	Organic Aerosols							
	Tars					7,174		
	Oils						696	
	Phenols							
	Fatty Acids							
	Other Constituents							
	Total	9,900	27,800	1,491	7,790	7,174	697	

TABLE E-2. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES – ILLINOIS NO. 6 COAL

	Stream No.	210	210S	10	10S	213	213S	
	Stream Name	Gas Liquor Synthesis Cases	Gas Liquor SNG Case	Quenched Lurgi Gas- Synthesis Cases	Quenched Lurgi Gas- SNG Case	AGR Offgases- Synthesis Cases	AGR Offgases- SNG Case	
kg-moles/hr	Hydrogen			7,455	8,632	22	26	
	Oxygen			21	21			
	Nitrogen/Argon			238	238	6	6	
	Carbon Monoxide			3,417	2,240	68	45	
	Carbon Dioxide	89	89	6,019	7,197	5,854	6,729	
	Methane			1,867	1,867	49	49	
	Ethane			98	98	56	56	
	Ethylene			14	14	8	8	
	Propane			16	16	16	16	
	Propylene			14	14	14	14	
	Butane			7.8	7.8	6.9	6.9	
	Butylene			14	14	12.4	12.4	
	C5+ Aliphatics			3.7	3.7	0.4	0.37	
	Benzene			16	16	0.63	0.72	
	Toluene			3.6	3.6	0.04	0.04	
	Other aromatics			2	2			
	Hydrogen Sulfide	4.3	4.3	175	176	174.8	175.8	
	Carbonyl Sulfide			2.2	1.2	2.2	1.2	
	Methyl Mercaptan			15	15	14.2	14.2	
	Ethyl Mercaptan			4.7	4.7	3.3	3.3	
	C3+ Mercaptans			0.61	0.61			
	Hydrogen Cyanide	0.70	0.70	0.48	0.48	0.23	0.23	
	Ammonia	143	143	0.0037	0.015			
	Hydrogen Chloride			0.2	0.2			
	Methanol					8.5	9.0	
	Total dry gas			19,404	20,582	6,317	7,173	
kg/hr	Water	494,840	475,636	612	530			
	Coal (MAF)							
	Ash							
	Particulates	38	38					
	Organic Aerosols							
	Tars	253	253					
	Oils							
	Phenols	1,152	1,152					
	Fatty Acids	192	192					
	Other Constituents	1,480	1,480					
	Total	506,610	485,406	429,930	451,208	272,077	309,989	

TABLE E-2. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ILLINOIS NO. 6 COAL

	Stream No.	216	216S	114	114S	12	12S	
	Stream Name	Methanol/Water Still Bottoms Synthesis Cases	Methanol/Water Still Bottoms SNG Case	By-Product Lurgi Naphtha Synthesis Cases	By-Product Lurgi Naphtha SNG Cases	Sulfur-Free Synthesis Gas Synthesis Cases	Sulfur-Free Synthesis Gas SNG Case	
kg-moles/hr	Hydrogen					7,433	8.606	
	Oxygen					21	21	
	Nitrogen/Argon					232	232	
	Carbon Monoxide					3,349	2,195	
	Carbon Dioxide					165	468	
	Methane					1,818	1,818	
	Ethane					42	42	
	Ethylene					6	6	
	Propane					0.04	0.04	
	Propylene							
	Butane			0.9	0.9			
	Butylene			1.6	1.6			
	C5+ Aliphatics			3.3	3.3			
	Benzene			15.4	15.3			
	Toluene			3.6	3.6			
	Other aromatics	0.004	0.004	2	2			
	Hydrogen Sulfide			0.2	0.2			
	Carbonyl Sulfide							
	Methyl Mercaptan			0.8	0.8			
	Ethyl Mercaptan			1.4	1.4			
	C3+ Mercaptans			0.61	0.61			
	Hydrogen Cyanide	0.007	0.008	0.24	0.24			
	Ammonia	0.046	0.048					
	Hydrogen Chloride	0.2	0.2					
	Methanol	0.018	0.019					
	Total dry gas	0.28	0.28			13,066	13,388	
kg/hr	Water	12,052	11,720					
	Total	12,061	11,721	2,288	2,218	155,355	138,575	

TABLE E-2. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ILLINOIS NO. 6 COAL

	Stream No.	228S	236S	110S				
	Stream Name	Methanation Condensate SNG Synthesis	Dehydration Offgases SNG Synthesis	Product SNG SNG Synthesis				
kg-moles/hr	Hydrogen			155				
	Oxygen							
	Nitrogen/Argon			232				
	Carbon Monoxide			2.2				
	Carbon Dioxide	0.1		23.8				
	Methane	0.4		4,550.7				
	Total dry gas	0.5		4,963.7				
kg/hr	Water	55,989	218	7				
	Total	56,002	218	82,357				

TABLE E-2. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ILLINOIS NO. 6 COAL

	Stream No.	117 ME	237 ME	18 ME	228 ME	231 ME	236 ME	110 ME
	Stream Name	Fuel Grade Methanol MeOH Synthesis	Methanol Wastewater MeOH Synthesis	Purge Gas to Methanation MeOH Synthesis	Methanation Condensate MeOH Synthesis	CO_2 Removal Offgas MeOH Synthesis	Dehydration Offgases MeOH Synthesis	Coproduct SNG MeOH Synthesis
kg-moles/hr	Hydrogen	0.02		961		0.006		12
	Oxygen							
	Nitrogen/Argon	0.02		232		0.07		232
	Carbon Monoxide	0.03		231		0.0004		1.2
	Carbon Dioxide	1.6		84.3	0.02	22.1		7.2
	Methane	1.0		1,817	0.06	0.77		2,192
	Ethane	0.26		41.7				
	Ethylene			6				
	Methanol	3,137	0.44	30				
	Ethanol	1.0	0.0001	0.006				
	Propanol	0.04	0.61	0.002				
	Acetone	2.1		0.63				
kg/hr	Water	100	1,406	7	8,181	25	290	3
	Total	101,500	1,456	50,180	8,183	987	290	43,569

TABLE E-2. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ILLINOIS NO. 6 COAL

	Stream No.	18 MM	107 MM	225 MM	226 MM	228 MM	231 MM	
	Stream Name	Purge & Expansion Gas to Methanation Mobil M Case	Crude Methanol Mobil M Case	Mobil M Wastewater	Fractionation Offgas to CO_2 Removal Mobil M	Methanation Condensate Mobil M	CO_2 Removal Offgas Mobil M	Dehydration Offgases Mobil M
kg-moles/hr	Hydrogen	961	0.03		0.8		0.006	
	Oxygen							
	Nitrogen/Argon	232	0.02		0.02		0.08	
	Carbon Monoxide	231	0.04	0.02	0.4		0.0006	
	Carbon Dioxide	84.3	1.8	0.5	2.7	0.02	24.6	
	Methane	1,817	1.2		21	0.06	0.85	
	Ethane	41.7	0.3		6		0.02	
	Ethylene	6			0.5		0.0002	
	Propane				2.3			
	Propylene				0.1			
	Butane				1.7			
	Butylene				0.1			
	C5+ Aliphatics			0.7	0.5			
	Methanol	30	3,157					
	Ethanol	0.006	1.0					
	Propanol	0.002	0.6					
	Acetone	0.6	2.1	4.1				
	Organic Acids			5.4				
	Total dry gas	3,403			36		25.6	
kg/hr	Water	7	1,506	58,100	39	8,181	28	
	Total	50,180	103,000	58,670	953	8,183	1,127	294

TABLE E-2. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ILLINOIS NO. 6 COAL

	Stream No.	110 MM	108 MM	109 MM	109 MM			
	Stream Name	Co-product SNG Mobil M	Blended Gasoline Mobil M	C_3 LPG Mobil M	C_4 LPG Mobil M			
kg-moles/hr	Hydrogen	12.8						
	Oxygen							
	Nitrogen/Argon	232						
	Carbon Monoxide	1.6						
	Carbon Dioxide	7.4						
	Methane	2,214						
	Ethane	6.0						
	Ethylene	0.5						
	Propane	2.3						
	Propylene	0.1						
	Butane	1.7						
	Butylene	0.1						
	C5+ Aliphatics	0.5						
	Total dry gas	2,479						
kg/hr	Water	297						
	Total	44,690	36,690	1,981	1,172			

TABLE E-2. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ILLINOIS NO. 6 COAL

	Stream No.	14 FT	219 FT	220 FT	228 FT	238 FT	231 FT	236 FT
	Stream Name	Purge Gas to Methanation F-T Case	Wastewater From Alcohol Recovery F-T Case	Fractionation Offgases to CO_2 Removal	Methanation Condensate F-T Case	Wastewater From CO_2 Removal F-T Case	CO_2 Removal Offgas F-T Case	Dehydration Offgas F-T Case
kg-moles/hr	Hydrogen	1,367		8.2			0.4	
	Nitrogen/Argon	228		3.7			0.6	
	Carbon Monoxide	51		0.96			0.004	
	Carbon Dioxide	340		175	0.04		241	
	Methane	1,959		147	0.15		7.3	
	Ethane	56		72			0.2	
	Ethylene	32		32			0.09	
	Propane			3			0.008	
	Propylene			31			0.08	
	Butene			0.006				
	Butylene			0.04				
	Pentane			0.002				
	Pentene			0.006				
	C7+ Aliphatics	0.8		0.1				
	Acetone		14.3					
	Total dry gas	4,042		474			249	
kg/hr	Water		70,970	328	19,440	393	270	364
	Total	59,630	71,830	15,080	19,444	393	11,010	364

TABLE E-2. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - ILLINOIS NO. 6 COAL

	Stream No.	110 FT	100 FT	101 FT	102 FT	105 FT	106 FT	106 FT
	Stream Name	Co-product SNG F-T Case	Blended Gasoline F-T Case	Diesel Oil F-T Case	Heavy Fuel Oil F-T Case	Mixed Alcohols F-T Case	C_3 LPG F-T Case	C_4 LPG F-T Case
kg-moles/hr	Hydrogen	98						
	Nitrogen/Argon	231						
	Carbon Monoxide	1.2						
	Carbon Dioxide	14						
	Methane	2,583						
	Ethane	71						
	Ethylene	32						
	Propane	3						
	Propylene	31						
	Butane	0.006						
	Butylene	0.04						
	Pentane	0.002						
	Pentene	0.006						
	C7+ Aliphatics	0.1						
	Total dry gas	3,065						
kg/hr	Water	4						
	Total	53,250	20,680	4,195	1,228	3,556	1,351	205

TABLE E-3. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - DUNN COUNTY LIGNITE

	Stream No.	1	21	2	3	4	5	205[a]
	Stream Name	Run-of-Mine Coal	Coal Fines	Prepared Coal	Steam	Oxygen	Raw Lurgi Gas	Low Pressure Coal Lockhopper Vent Gas
kg-moles/hr	Hydrogen						7,453	5.9
	Oxygen					2,610		
	Nitrogen/Argon					159	162	0.13
	Carbon Monoxide						3,005	2.4
	Carbon Dioxide						6,098	4.8
	Methane						2,078	1.6
	Ethane						113	0.09
	Ethylene						19.3	0.015
	Propane						15.3	0.012
	Propylene						13.3	0.011
	Butane						7.8	0.006
	Butylene						13.3	0.011
	C5+ Aliphatics						9.6	0.008
	Benzene						11.5	0.009
	Toluene						2.2	0.002
	Other aromatics						2	0.002
	Hydrogen Sulfide						76	0.06
	Carbonyl Sulfide						1.0	0.001
	Methyl Mercaptan						6.7	0.005
	Ethyl Mercaptan						2.2	0.002
	C3+ Mercaptans						0.29	0.0002
	Hydrogen Cyanide						1.2	0.001
	Ammonia						78.3	0.062
	Hydrogen Chloride						0.19	0.0002
	Methanol							
	Total dry gas					2,769	19,233	15.2
kg/hr	Water	220,140	66,040	154,100	423,490		434,162	2.2
	Coal (MAF)	311,740	93,520	218,220				
	Ash	39,030	11,710	27,320				
	Particulates						988	0.068
	Organic Aerosols							2.5
	Tars						12,915	
	Oils						2,940	
	Phenols						1,129	
	Fatty Acids						103	
	Other Constituents						1,887	
	Total	570,910	171,270	399,640	423,490	89,260	873,400	337

[a] Assumes Lurgi gas is used as the lockhopper pressurant. Composition shown excludes ejection air.

TABLE E-3. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - DUNN COUNTY LIGNITE (Continued)

	Stream No.	239	403	206	209	111	112	
	Stream Name	Ash Quench Makeup Water	Quenched Ash	Ash Lock Vent Gas	Gas Liquor Depressurization Gas	Tar	Oil	
kg-moles/hr	Hydrogen							
	Oxygen			13.4				
	Nitrogen/Argon			0.8				
	Carbon Monoxide				1.6			
	Carbon Dioxide				134			
	Methane				5.3			
	Ethane				0.26			
	Ethylene				0.26			
	Propane				0.31			
	Propylene				0.31			
	Butane				0.31			
	Butylene				0.31			
	C5+ Aliphatics				0.55			
	Benzene				1.5			
	Toluene				0.18			
	Other aromatics				0.021			
	Hydrogen Sulfide				1.4			
	Carbonyl Sulfide				0.017			
	Methyl Mercaptan				0.5			
	Ethyl Mercaptan				0.33			
	C3+ Mercaptans				0.044			
	Hydrogen Cyanide				0.0085			
	Ammonia				1.6			
	Hydrogen Chloride							
	Methanol							
	Total dry gas			14.2	149			
kg/hr	Water	12,700	7,200	1,448	140			
	Coal (MAF)							
	Ash		28,600					
	Particulates			3.3		962	5.9	
	Organic Aerosols							
	Tars					12,780		
	Oils						2,940	
	Phenols							
	Fatty Acids							
	Other Constituents							
	Total	12,700	35,800	1,909	6,550	13,740	2,946	

TABLE E-3. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - DUNN COUNTY LIGNITE (Continued)

	Stream No.	210	210S	10	10S	213	213S	
	Stream Name	Gas Liquor Synthesis Cases	Gas Liquor SNG Case	Quenched Lurgi Gas- Synthesis Cases	Quenched Lurgi Gas- SNG Case	AGR Offgases- Synthesis Cases	AGR Offgases- SNG Case	
kg-moles/hr	Hydrogen			7,453	8,298	22	25	
	Oxygen							
	Nitrogen/Argon			162	162	4	4	
	Carbon Monoxide			3,003	2,158	60	43	
	Carbon Dioxide	76.5	76.5	5,887	6,732	5,462	6,274	
	Methane			2,073	2,073	54	54	
	Ethane			113	113	65	65	
	Ethylene			19	19	11	11	
	Propane			13	15	15	15	
	Propylene			13	13	13	13	
	Butane			7.5	7.5	6.6	6.6	
	Butylene			13	13	11.5	11.5	
	C5+ Aliphatics			9	9	0.9	0.9	
	Benzene			10	10	0.58	0.66	
	Toluene			2	2	0.04	0.04	
	Other aromatics			2	2			
	Hydrogen Sulfide	0.65	0.65	74	74.4	73.9	74.3	
	Carbonyl Sulfide			1.0	0.64	1.0	0.64	
	Methyl Mercaptan			6.2	6.2	5.9	5.9	
	Ethyl Mercaptan			1.9	1.9	1.3	1.3	
	C3+ Mercaptans			0.25	0.25			
	Hydrogen Cyanide	0.78	0.78	0.37	0.22	0.18	0.10	
	Ammonia	78.6	78.6	0.068	0.227	0.027	0.18	
	Hydrogen Chloride			0.19	0.19			
	Methanol					8.3	8.6	
	Total dry gas			18,865	19,714	5,815	6,615	
kg/hr	Water	433,410	418,208	612	604			
	Coal (MAF)							
	Ash							
	Particulates	26	26					
	Organic Aerosols							
	Tars	135	135					
	Oils							
	Phenols	1,129	1,129					
	Fatty Acids	103	103					
	Other Constituents	1,887	1,887					
	Total	441,440	426,238	408,170	423,780	250,868	286,134	

TABLE E-3. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - DUNN COUNTY LIGNITE (Continued)

	Stream No.	216	216S	114	114S	12	12S	
	Stream Name	Methanol/Water Still Bottoms Synthesis Cases	Methanol/Water Still Bottoms SNG Case	By-Product Lurgi Naphtha Synthesis Cases	By-Product Lurgi Naphtha SNG Cases	Sulfur-Free Synthesis Gas Synthesis Cases	Sulfur-Free Synthesis Gas SNG Case	
kg-moles/hr	Hydrogen					7,431	8,273	
	Oxygen							
	Nitrogen/Argon					158	158	
	Carbon Monoxide					2,943	2,115	
	Carbon Dioxide					425	458	
	Methane					2,019	2,019	
	Ethane					48	48	
	Ethylene					8	8	
	Propane					0.1	0.1	
	Propylene							
	Butane			0.9	0.9			
	Butylene			1.5	1.5			
	C5+ Aliphatics			8.0	8.0			
	Benzene			9.4	9.3			
	Toluene			2	2			
	Other aromatics	0.003	0.004	2	2			
	Hydrogen Sulfide			0.1	0.1			
	Carbonyl Sulfide							
	Methyl Mercaptan			0.3	0.3			
	Ethyl Mercaptan			0.6	0.6			
	C3+ Mercaptans			0.25	0.25			
	Hydrogen Cyanide	0.006	0.007	0.19	0.11			
	Ammonia	0.036	0.046					
	Hydrogen Chloride	0.19	0.19					
	Methanol	0.014	0.018					
	Total dry gas	0.25	0.27			13,032	13,079	
kg/hr	Water	10,112	10,054					
	Total	10,120	10,063	1,900	1,890	155,471	135,423	

TABLE E-3. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - DUNN COUNTY LIGNITE (Continued)

	Stream No.	228S	236S	110S				
	Stream Name	Methanation Condensate SNG Synthesis	Dehydration Offgases SNG Synthesis	Product SNG SNG Synthesis				
kg-moles/hr	Hydrogen			116.5				
	Oxygen							
	Nitrogen/Argon			158				
	Carbon Monoxide			1.1				
	Carbon Dioxide	0.1		20.4				
	Methane	0.4		4,682.5				
	Total dry gas	0.5		4,978.5				
kg/hr	Water	53,585	208	7				
	Total	53,597	208	81,618				

TABLE E-3. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - DUNN COUNTY LIGNITE (Continued)

	Stream No.	117 ME	237 ME	18 ME	228 ME	231 ME	236 ME	110 ME
	Stream Name	Fuel Grade Methanol MeOH Synthesis	Methanol Wastewater MeOH Synthesis	Purge Gas to Methanation MeOH Synthesis	Methanation Condensate MeOH Synthesis	CO_2 Removal Offgas MeOH Synthesis	Dehydration Offgases MeOH Synthesis	Coproduct SNG MeOH Synthesis
kg-moles/hr	Hydrogen	0.03		1,342		0.05		52
	Oxygen							
	Nitrogen/Argon	0.01		158		0.10		158
	Carbon Monoxide	0.03		203		0.0008		1.0
	Carbon Dioxide	4		217	0.03	50		5.2
	Methane	1.1		2,018	0.12	1.8		2,484
	Ethane	0.30		48				
	Ethylene			8				
	Methanol	2,895	1.2	38				
	Ethanol	0.95	0.0003	0.008				
	Propanol	0.015	0.58	0.0009				
	Acetone	1.7		0.79				
kg/hr	Water	91	3,644	9	15,170	56	321	3
	Total	93,170	3,716	57,650	15,173	2,288	321	45,638

TABLE E-3. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - DUNN COUNTY LIGNITE (Continued)

	Stream No.	18 MM	107 MM	225 MM	226 MM	228 MM	231 MM	236 MM
	Stream Name	Purge & Expansion Gas to Methanation Mobil M Case	Crude Methanol Mobil M Case	Mobil M Wastewater	Fractionation Offgas to CO_2 Removal Mobil M	Methanation Condensate Mobil M	CO_2 Removal Offgas Mobil M	Dehydration Offgases Mobil M
kg-moles/hr	Hydrogen	1,342	0.04		0.8		0.05	
	Oxygen							
	Nitrogen/Argon	158	0.02		0.01		0.1	
	Carbon Monoxide	203	0.03	0.02	0.4		0.001	
	Carbon Dioxide	217	4.7	0.9	4.8	0.03	54.8	
	Methane	2,018	1.3		19.6	0.12	1.9	
	Ethane	48	0.35		5.5		0.004	
	Ethylene	8			0.5		0.0004	
	Propane				2.1			
	Propylene				0.1			
	Butane				1.6			
	Butylene				0.1			
	C5+ Aliphatics			0.6	0.44			
	Methanol	38	2,897					
	Ethanol	0.008	0.95					
	Propanol	0.0009	0.60					
	Acetone	0.79	1.7	3.8				
	Organic Acids			4.9				
	Total dry gas	4,032			35.9		56.9	
kg/hr	Water	9	3,730	55,650	37	15,170	62	325
	Total	57,650	96,940	56,200	982	15,173	2,507	325

TABLE E-3. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - DUNN COUNTY LIGNITE (Continued)

	Stream No.	110 MM	108 MM	109 MM	109 MM			
	Stream Name	Co-product SNG Mobil M	Blended Gasoline Mobil M	C_3 LPG Mobil M	C_4 LPG Mobil M			
kg-moles/hr	Hydrogen	53						
	Oxygen							
	Nitrogen/Argon	158						
	Carbon Monoxide	1.4						
	Carbon Dioxide	5.3						
	Methane	2,504						
	Ethane	5.5						
	Ethylene	0.5						
	Propane	2.1						
	Propylene	0.1						
	Butane	1.6						
	Butylene	0.1						
	C5+ Aliphatics	0.4						
	Total dry gas	2,732						
kg/hr	Water	3						
	Total	46,389	33,650	1,818	1,075			

TABLE E-3. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - DUNN COUNTY LIGNITE (Continued)

	Stream No.	14 FT	219 FT	220 FT	228 FT	238 FT	231 FT	236 FT
	Stream Name	Purge Gas to Methanation F-T Case	Wastewater From Alcohol Recovery F-T Case	Fractionation Offgases to CO_2 Removal	Methanation Condensate F-T Case	Wastewater From CO_2 Removal F-T Case	CO_2 Removal Offgas F-T Case	Dehydration Offgas F-T Case
kg-moles/hr	Hydrogen	1,385		8.3			0.3	
	Nitrogen/Argon	155		2.6			0.4	
	Carbon Monoxide	75		1.4			0.005	
	Carbon Dioxide	321		166	0.04		227	
	Methane	2,131		161	0.15		7.9	
	Ethane	57		73			0.2	
	Ethylene	31		32			0.08	
	Propane			2.9			0.008	
	Propylene			30			0.08	
	Butane			0.006				
	Butylene			0.04				
	Pentane			0.002				
	Pentene			0.006				
	C7+ Aliphatics	0.8		0.1				
	Acetone		13.6					
	Total dry gas	4,157		477			236	
kg/hr	Water		72,430	335	18,820	371	256	378
	Total	60,230	73,240	14,840	18,824	371	10,390	378

TABLE E-3. CALCULATED MATERIAL FLOWS FOR LURGI-BASED SYNTHETIC FUELS FACILITIES - DUNN COUNTY LIGNITE (Continued)

	Stream No.	110 FT	100 FT	101 FT	102 FT	105 FT	106 FT	106 FT
	Stream Name	Co-product SNG F-T Case	Blended Gasoline F-T Case	Diesel Oil F-T Case	Heavy Fuel Oil F-T Case	Mixed Alcohols F-T Case	C_3 LPG F-T Case	C_4 LPG F-T Case
kg-moles/hr	Hydrogen	93						
	Nitrogen/Argon	157						
	Carbon Monoxide	1.8						
	Carbon Dioxide	14						
	Methane	2,779						
	Ethane	73						
	Ethylene	32						
	Propane	3						
	Propylene	30						
	Butane	0.006						
	Butylene	0.04						
	Pentane	0.002						
	Pentene	0.006						
	C7+ Aliphatics	0.1						
	Total dry gas	3,183						
kg/hr	Water	5						
	Total	54,320	19,690	3,993	1,169	3,386	1,286	195